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ASSESSMENT OF ENERGY STORAGE TECHNOLOGIES AND SYSTEMS

PHASE I:
ELECTRIC STORAGE HEATING, STORAGE AIR CONDITIONING, AND STORAGE HOT WATER HEATERS

by

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ENERGY AND ENVIRONMENTAL SYSTEMS DIVISION

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August 1976

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ABSTRACT

This study analyzes the commercial feasibility of thermal energy storage (TES) in buildings; TES applications examined include storage electric (resistance) heating, storage air conditioning, and storage hot water heating.

A system model, SIMSTOR, is employed to simulate TES-related effects upon daily and annual utility load profiles and to compare utility fuel and capital cost savings with TES-system costs. Case-study analyses of TES applications for a representative set of utility service areas indicate that several already- and near-commercial TES systems are cost-effective. Alternative strategies to commercialize these systems are examined and the preferred strategies are identified.

1. *INTRODUCTION AND SUMMARY*

1.1 *SCOPE AND OBJECTIVES*

This report presents the findings of the first phase of a study to determine the commercial feasibility of thermal energy storage in buildings. The storage systems under evaluation are systems and devices installed on the customer's premises for the purpose of storing off-peak electric energy for thermal applications during peak-load hours. The economic rationale for the systems is that the marginal cost of utility-supplied power is considerably lower during off-peak hours than during on-peak hours.

The first phase of the study has examined the commercial feasibility of three storage applications: storage used in conjunction with direct (resistance) electric heating, storage electric air conditioning, and storage hot water supply. Subsequent phases of the study will examine thermal storage in heat pump, solar energy, and industrial process-heat applications and will compare customer storage with utility storage systems.

The principal objectives of the study are to:

- Determine the cost-effectiveness of customer thermal energy storage (TES) systems over a representative sample of electric utility service areas,
- Specify alternative strategies for commercializing cost-effective TES systems, and
- Identify TES technologies likely to offer high payback on R&D investment.

1.2 *SUMMARY OF STUDY FINDINGS*

1.2.1 *Cost-Effectiveness Evaluation*

The cost-effectiveness of residential applications of storage space heating, storage air conditioning, and storage hot water heaters was evaluated.

Method

A case studies approach was adopted to evaluate the TES systems. For each TES system, utility savings were estimated and compared with TES system costs for a number of utility service areas. The four service areas for which detailed results are presented here were selected to illustrate the important factors affecting the cost-effectiveness of the individual types of systems.* In each service area the TES systems were matched to the requirements of a 1500 ft^2, well insulated, detached single family dwelling unit.

A computer simulation model, SIMSTOR, was developed to calculate the utility costs of meeting conventional and TES loads. The model uses hourly load and tri-hourly weather data and TES- and conventional-system performance characteristics to generate load profiles over a full annual (8760 hour) cycle. It then calculates the incremental (marginal) utility capital and fuel costs to meet changes in the utility's load. SIMSTOR incorporates a load dispatch model and observes operating constraints such as scheduled and forced outages and the cycle time of each type of generating unit. It calculates transmission and distribution costs as well as generating costs.

Because SIMSTOR uses an equilibrium method to solve for optimum plant capacity and mix, the estimated utility savings represent long-run marginal cost savings. Therefore, the savings estimates pertain to planning horizons beyond the construction times of projects to which utilities are already firmly committed. The method's neglect of short-term effects is not considered a serious limitation, however. The times required to deploy TES systems in numbers sufficient to produce significant load-leveling effects are comparable to the construction periods of base-load generating plants.

Except for differences due to different equipment lifetimes, annual utility capital cost savings and TES capital costs were calculated on the basis of the same capital charge rate. Because charge rates representative of recent utility experience were used, the accounting procedure is conceptually equivalent to assuming utility ownership of the storage system, although in practice this need not be the case and, from the point of view of the utility, may not be desirable. Levelized annual fuel savings were computed under an assumed 0% real escalation rate and on the basis of the same discount (cost-of-money) factor used in estimating annual capital costs.

Cost/performance data for TES systems were obtained from a number of sources. For commercially available systems, these sources included sales

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*Results are presented for two summer-peaking utilities and two winter-peaking utilities. Further characteristics are given in Table 4.1.

representatives, manufacturers, distributors, and retailers, and, for advanced systems, engineering-research groups.

In characterizing electric storage heating systems, the study relied heavily on data for commercially available European systems. Data for storage hot water heaters were obtained primarily from U.S. manufacturers and retailers. Because there are no commercially available TES space-cooling systems, cost/performance estimates were developed from data for systems either in the development or test phases.

Study Results

For a specific TES system, utility savings per TES installation were found to be critically dependent on several variables: the utility's annual and daily load factors, the TES charging cycle, and the level of TES market penetration. TES storage was not considered in those service areas having access to low cost conventional hydroelectric power for meeting intermediate and peak power demands.

Table 1.1 gives utility savings and TES costs, by service area, for several TES systems for selected levels of market penetration. Storage space heating was found to be cost-effective in both of the service areas (A and B) supplied by winter peaking utilities. For storage air conditioning, in the two areas (C and D) supplied by summer peaking utilities, the utility savings were slightly greater than the TES costs in Service Area C, and greatly exceeded TES costs in Service Area D. Utility savings exceeded TES costs for storage hot water heaters in all four areas.

The net benefits of storage space heating were lower in Service Area B than in Service Area A. As shown in Fig. 1.1, Service Area B was scheduled-maintenance constrained, so that reductions in winter peak loads did not translate into equal reductions in total capacity requirements. As indicated in Fig. 1.2, neither of the summer peaking utilities encountered a scheduled maintenance problem at TES market penetrations yielding maximum net benefits.

Table 1.2 provides a more detailed breakdown of the utility savings that result from the storage-related reduction in system peak capacity. It is important to note that the generation peak capacity reduction in Table 1.2, as compared to the measured reduction shown in Table 1.1, has been appropriately adjusted upward by a reserve requirement factor of approximately 1.2.

Table 1.1. Utility Savings and TES Costs

Service Area	TES System	Discharge Period (hr)	No. of TES Customers	Generation Peak Load Reduction (MW_e)	(% of Peak)	Average Utility Savings ($/yr/Customer) Capital Gen.	Capital Tran.	Capital Dist.	Variable Fuel	Variable O&M	Variable Cycle	Total	TES Incremental Cost ($/yr/ Customer)	Total Net Savings (10^6\$/yr)
A	Water Htg.	4	50,000[b]	24	3.3	37	15	11	-7	-1	4	58	26	1.61
A	Water Htg.	16	50,000[b]	40	5.5	93	24	-14	16	2	11	132	80	2.60
A	Space Htg.	8	2,800[a]	40	5.5	841	441	-36	127	19	30	1,421	568[c]	2.37
B	Water Htg.	4	34,400[a]	41	4.3	68	36	12	-5	-1	4	114	26	3.02
B	Water Htg.	16	37,500[b]	46	4.8	161	37	-9	-8	-1	10	190	80	4.13
B	Space Htg.	8	5,800[a]	41	4.3	686	217	-94	-46	-7	38	794	552[c]	1.40
C	Water Htg.	4	145,000[b]	114	0.9	40	23	-10	-9	-2	5	48	26	3.08
C	Water Htg.	16	145,000[b]	114	0.9	108	23	20	-24	-4	8	131	80	7.4
C	Space Htg.	8	54,000[b]	0	0	220	0	0	-136	-23	40	152	552[c]	-21.5
C	Air Cond.	8	219,000[a]	945	7.7	163	127	35	32	6	1	365	252	24.7
D	Water Htg.	4	28,100[b]	29	1.5	47	31	22	2	0	8	110	26	2.36
D	Water Htg.	16	28,100[b]	29	1.5	72	32	22	31	6	17	180	80	2.81
D	Air Cond.	8	18,300[a]	141	7.5	355	234	198	121	22	21	950	305	11.8

[a]Number of TES customers at which total net benefits are maximized (N=N*).

[b]Number of TES customers at which the aggregate TES design-day kilowatt-hour load equals the aggregate design-day kilowatt-hour load of existing conventional-system customers ($N=N_s$).

[c]Refers to 10-unit dispersed storage space heating system. Corresponding incremental costs for central furnace system: Service Area A: \$388/yr, Service Areas B and C: \$310/yr.

Table 1.2. Utility Savings per Kilowatt of System Peak Capacity Reduction

Service Area	TES System	Discharge Period (hr)	Generation Peak Capacity Reduction (MW_e)[a]	Average Utility Savings ($/yr/kW) Capital Gen.	Capital Tran.	Capital Dist.	Total Gen.[b]	Total System	TES Incremental Cost ($/yr/kW)	Net Savings ($/yr/kW)
A	Water Htg.	4	29	64	26	19	57	101	45	56
A	Water Htg.	16	48	97	25	-15	127	138	83	54
A	Space Htg.	8	48	49	26	-2	59	83	33	49
B	Water Htg.	4	49	48	25	8	46	80	18	61
B	Water Htg.	16	55	109	25	-6	110	129	54	75
B	Space Htg.	8	49	81	26	-11	79	94	65	28
C	Water Htg.	4	131	44	25	-11	38	53	29	24
C	Water Htg.	16	131	120	25	22	97	145	89	56
C	Air Cond.	8	1087	33	26	7	41	74	51	23
D	Water Htg.	4	34	39	25	18	47	90	21	69
D	Water Htg.	16	34	59	26	18	104	148	66	82
D	Air Cond.	8	166	39	26	22	57	105	34	71

[a]This column gives the peak load savings from Table 1.1 scaled upward by the reserve requirement factor.

[b]Total Generation Savings = Generation Savings + Variable Savings (Fuel, O&M, Cycle).

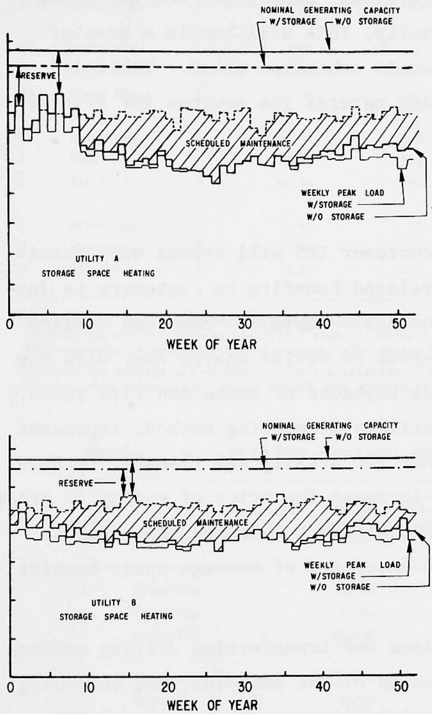

Fig. 1.1. Effect of Storage Space Heating on Utility Weekly Peak Loads, Service Areas A and B

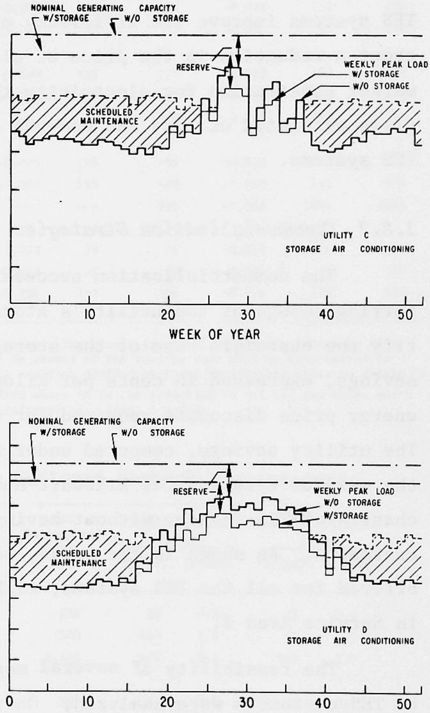

Fig. 1.2. Effect of Storage Air Conditioning on Utility Weekly Peak Loads, Service Areas C and D

An unexpected finding is that in some service areas TES systems will have little effect on long-run utility oil consumption. As described in Sec. 5.2.3, changes in utility oil consumption are very sensitive to the outputs of oil- and coal (or nuclear)-fired generating plant. In many utility service areas a more important oil saving will occur as a result of the displacement of oil and natural gas from end-use markets. To the extent that TES systems improve the efficiency of electricity supply and thereby bring about a reduction in the price of electricity, this will enable a greater market penetration for electricity than would otherwise occur. Table 1.3 gives estimated utility and end-use oil and natural gas savings for several TES systems.

1.2.2 Commercialization Strategies

The commercialization success of customer TES will depend upon transferring enough of the utility's storage-related benefits to customers to justify the customers' use of the storage devices. Table 1.4 compares utility savings, expressed in cents per kilowatt-hour of device energy use, with the energy price discounts required for simple paybacks of three and five years. The utility savings, computed under the utility accounting method, represent the maximum revenues per kilowatt-hour that the utility can transfer to purchasers of TES devices without having to increase the price of energy to other customers. As shown in the table, paybacks as short as three years can be offered for all the TES systems, with the exception of storage space heating in Service Area B.

The feasibility of several mechanisms for transferring utility savings to TES customers were analyzed, On the basis of the analyses, the following recommendations were developed for commercializing the three types of TES systems.

Electric Storage Space Heating

The recommended strategy is the offering of load management contract rates. In those service areas where electric storage heating is cost-effective, the standard space heating rate is usually high enough ($\geq$3.0¢/kWh) to allow a rate discount adequate to give the customer a simple five-year payback. If TES market penetration is expected to be high, the utility should consider

Table 1.3. TES-Induced Oil and Gas Savings, Residential Market

					3-Year TES Payback			5-Year TES Payback		
Service Area	TES System	Discharge Period (hrs)	Residential Oil and Gas Consumption (10^6bbls/yr, equiv.)	Utility Oil Savings (10^3bbls/yr)	$(\Delta P/P)^a$	End-Use Oil Savings[b] (10^3bbls per yr)	Total Oil Savings (10^3bbls per yr)	$(\Delta P/P)^a$	End-Use Oil Savings (10^3bbls per yr)	Total Oil Savings (10^3bbls per yr)
A	Water Htg.	4	3.84	-25	-0.026	45	20	-0.043	72	47
A	Water Htg.	16	3.84	68	-0.029	49	117	-0.078	132	200
A	Space Htg.	8	3.84	33	-0.030	52	85	-0.055	93	126
B	Water Htg.	4	4.02	-4	-0.073	129	125	-0.085	152	148
B	Water Htg.	16	4.02	-47	-0.083	148	101	-0.126	224	177
B	Space Htg.	8	4.02	-33	---	---	-33	-0.038	66	33
C	Water Htg.	4	66.54	-175	-0.004	106	-69	-0.008	219	49
C	Water Htg.	16	66.54	-265	-0.007	195	-70	-0.019	544	279
C	Air Cond.	8	66.54	791	---	---	791	-0.061	1791	2582
D	Water Htg.	4	2.85	17	-0.023	29	46	-0.028	34	51
D	Water Htg.	16	2.85	45	-0.022	28	73	-0.036	44	89
D	Air Cond.	8	2.85	162	-0.101	127	289	-0.136	172	334

[a]The quantity $\Delta P/P$ represents fractional change in electricity price. The change in price, ΔP, is determined by first calculating utility "excess benefits," that is, those benefits in excess of the savings that must be transferred to TES customers to provide required payback. The excess benefits are then divided by total residential sales to obtain ΔP.

[b]End-use oil savings are estimated from the relation $\Delta Q = \beta(\Delta P/P)Q$ where ΔQ is the reduction in oil and gas sales and β is the cross price elasticity of demand with respect to electricity price. Here, $\beta = 0.44$.

Table 1.4. Utility Savings versus Customer Payback Requirements

						Payback Required to Commercialize[c]			
						3-Year		5-Year	
Service Area	TES System	Discharge Period[a] (hrs)	Annual Consumption (kWh)	Utility Savings[b] (¢/kWh)	TES Incremental Cost ($)	($/yr)	(¢/kWh)	($/yr)	(¢/kWh)
A	Water Htg.	4	5,840	1.0	105	35	0.6	21	0.4
A	Water Htg.	16	5,840	2.3	320	107	1.8	64	1.1
A	Space Htg.	8	28,000	5.1	2,840	946	3.4	568	2.0
B	Water Htg.	4	5,840	2.0	105	35	0.6	21	0.4
B	Water Htg.	16	5,840	3.3	320	107	1.8	64	1.1
B	Space Htg.	8	27,600	2.9	2,760	945	3.4	552	2.0
C	Water Htg.	4	5,840	0.8	105	35	0.6	21	0.4
C	Water Htg.	16	5,840	2.2	320	107	1.8	64	1.1
C	Air Cond.	8	2,500	14.6	1,095	365	14.6	219	8.8
D	Water Htg.	4	5,840	1.9	105	35	0.6	21	0.4
D	Water Htg.	16	5,840	3.1	320	107	1.8	64	1.1
D	Air Cond.	8	6,500	14.6	1,325	442	6.9	265	4.1

[a]Discharge periods for air conditioning and space heating systems correspond to devices in Table 1.1. For storage hot water heaters, the 16-hour system offers the greatest net benefits; the 4-hour system is included because it is the easiest to commercialize.

[b]Utility savings per kWh calculated from annual consumption column and from annual utility savings in Table 1.1.

[c]Simple payback; does not include cost of capital.

installing ripple or other real-time control systems to maximize the load leveling benefits.

Storage Air Conditioning

Because the rate discount required to commercialize is so large, utility ownership may be the only feasible strategy. Certainly in Service Area C, it would be difficult to devise any politically acceptable combination of monthly credits and energy-price discounts that would provide an adequate return on the customer's initial investment. In warmer climates, where energy use for air conditioning is much larger (for example, Service Area D), it may be possible to design and implement an acceptable load management contract rate.

Hot Water Heaters

Although storage water heaters with long storage times offer greater net savings than water heaters with short discharge periods (see Table 1.1), they are likely to be more difficult to commercialize. These systems require the customer to invest in a larger tank, whereas the systems with short discharge periods require only the addition of a control device to the standard tank.

A simple method to commercialize the smaller tanks is for the utility to offer the customer a credit (ranging from \$4.25 to \$9.50 per month for the utilities evaluated) for the right to interrupt service. For the larger tanks, the granting of a rate discount, usually of the order of 1¢/kWh during the off-peak hours, will provide an adequate payback on the customer's investment in a TES system.

1.2.3 R&D Recommendations

The outstanding study finding is that already-commercial and near-commercial customer TES systems are cost-effective. Accordingly, the R&D recommendations have been divided into two parts: near term R&D in direct support of applications of existing technologies and R&D to advance TES technology over the long term.

R&D for Near Term Application

- Development, for the utility industry and its regulators, of improved methods for evaluating the potential benefits of TES technologies.
- Joint ERDA and utility sponsorship of field experiments to measure the operating and performance characteristics of storage heating and storage air conditioning equipment and control systems.
- Projects, conducted jointly by electric utilities and air conditioner manufacturers, to develop and test improved storage air conditioner and storage heat pump designs.
- Technical assistance and planning support for electric utilities indicating an interest in deploying TES systems. This could be especially helpful and effective for small utilities.

R&D for Long Term Application

In a number of storage applications, the operating temperature range available for storage of sensible heat precludes the use of compact, low-cost storage devices. Given the large potential benefits in storage air conditioning applications, further R&D on phase-change materials appears to be justified. Other storage concepts that may offer large benefits include: seasonal storage for solar energy applications and for utility load leveling, and hybrid storage concepts providing hot and cold storage.

It is recommended that evaluation of the benefits of advanced storage technologies be initiated early in the research and development phase. The cost and performance of advanced concepts should be compared against the cost and performance of commercially available systems.

2. *BACKGROUND AND OVERVIEW*

2.1 *THE BASIC CONCEPT OF CUSTOMER TES*

The basic idea underlying thermal energy storage is illustrated in Fig. 2.1. By displacing energy consumption from the electric utility's peak-load period to the off-peak period, thermal energy storage produces the following economic benefits:

a. A reduction in the growth rate of the utility's peak loads with a corresponding reduction in generation, transmission, and distribution capacity from what would otherwise be required,

b. Improved daily load factors, allowing substitution of base-load generating plant and fuels for peak- and intermediate- load generating plant and fuels, and

c. A reduction in the cost of electricity supply, thereby enabling a greater market penetration for electricity than could otherwise occur.*

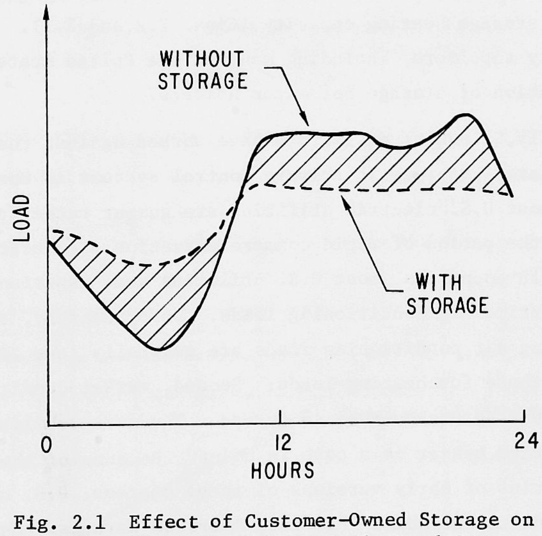

Fig. 2.1 Effect of Customer-Owned Storage on Electric Utility Daily Load Curve

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*As shown in Chapter 5, for most utility service areas the savings of scarce fuels (oil and natural gas) through this substitution probably exceed those under (b).

Against these benefits, occurring mostly on the utility side of the electric meter, must be weighed the additional capital costs on the customer side of the meter.* It is only when the benefits exceed the extra customer costs that it is economical to encourage the installation of the thermal storage systems. If the customer, rather than the utility, is to finance and own the storage system, the utility can provide the needed encouragement through a number of mechanisms. Time-of-use rate schedules, peak-period demand charges, load management contract rates, or simple monthly credits can be introduced to allow customers to realize the required payback on their additional capital investment.

2.2 *COMMERCIAL PROSPECTS FOR TES*

Commercial applications of TES technologies are not new. Utilities in a number of European countries have vigorously promoted the installation of electric storage heating systems since the late 1950s. Today, Great Britain and the Federal Republic of Germany each have approximately 20,000 MWe of installed storage heating capacity (Figs. 2.2 and 2.3). For many years, electricity suppliers, including many in the United States, have encouraged installation of storage hot water heaters.

Historically, a number of factors have worked against the commercial application of thermal storage in climate control systems in the United States. First, most U.S. electric utilities are summer rather than winter peaking. During the period of rapid commercialization of electric storage heating in European countries, most U.S. utilities were experiencing a build-up of their summertime air conditioning loads. Unfortunately, the technologies for displacing air conditioning loads are generally less advanced and more costly than those for heating loads. Second, market conditions are different in the United States than in Europe. The marketability of the free-standing storage heater is a case in point. Because of the poor performance characteristics of early versions of these systems, U.S. utilities may have been reluctant to introduce them into American markets. Meanwhile, the systems could be introduced and perfected in Europe where they satisfied a

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*Under rate regulation, of course, most of the benefits eventually flow to the customer's side of the meter.

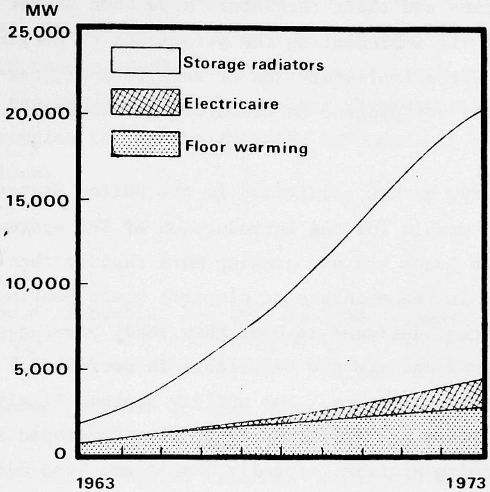

Fig. 2.2. Growth of Installed Electric Storage Heating Capacity in Great Britain

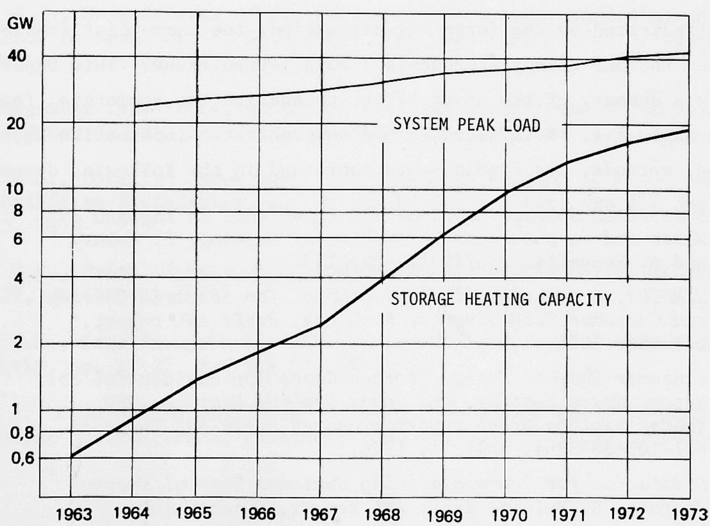

Fig. 2.3. Growth in Installed Storage Heating Capacity in Relation to Total System Peak Load, West Germany

large market as replacements for stove heaters in older homes and buildings. Finally, U.S. utilities and their regulators have been slower than their European counterparts in implementing the principles of marginal cost pricing. As noted above, the implementation of some form of peak-load pricing is a necessary part of any program to commercialize customer-owned storage systems.

In recent years, market conditions in the United States have become considerably more favorable for the introduction of TES systems. In many service areas, winter loads are now growing more rapidly than summer loads because of the rapid increase in use of electric space heating.* European storage heating systems, designed to meet this load, have been considerably improved over the years and are now comparable in performance to conventional direct resistance heating systems. For utility systems likely to continue to face summer peak loads, several U.S. firms have developed and are testing storage air conditioning systems. Equally important, load management and the implementation of more efficient electric rates appear to be ideas whose times have arrived for many U.S. utilities and utility regulatory commissions.

2.3 REPORT OBJECTIVES AND ORGANIZATION

As indicated by the foregoing discussion, the commercial feasibility of customer thermal energy storage is a complicated issue. This report presents only a summary of the study effort to analyze the commercial feasibility of TES technologies. More detailed and comprehensive information about the study data, methods, and findings are contained in the following documents:

- *Electrical Storage Heating: The Experience in England and Wales and in the Federal Republic of Germany,* J. Asbury and A. Kouvalis, ANL/ES-50, May 1976.
- *SIMSTOR, A Computer Simulation Model for Electric Utility and Customer Technologies,* R. Giese, draft ANL report, December 1976.
- *Consumer Thermal Energy Storage Costs for Residential Hot Water, Space Heating, and Space Cooling Systems,* TRW Energy Systems Group report prepared under ANL Contract #31-109-38-3364, July 31, 1976.
- *Strategies for Commercializing Customer Thermal Energy Storage,* S. Nelson, draft ANL report, October 1976.

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*In 1974, 50% of the new homes built in the United States were equipped with electric space-heating systems. The estimate for 1975 is 60%.

The remainder of this report is divided into three chapters. The next chapter describes the overall study approach and the analytical methods of the TES analysis. Chapter 4 discusses the utility service areas and TES systems for which the cost-effectiveness analyses were performed. Finally, Chapter 5 gives the results of the cost-effectiveness analyses, discusses alternative strategies for commercializing TES systems, and makes several R&D recommendations.

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3. *STUDY METHODOLOGY*

3.1 *INTRODUCTION*

This chapter describes the methodology used to achieve the three Phase I study objectives:

- Analyze the cost-effectiveness of TES applications in: electric storage heating, storage air conditioning, and storage hot water heaters.
- Specify TES commercialization strategies.
- Make TES research and development recommendations.

3.2 *COST EFFECTIVENESS ANALYSIS*

3.2.1 *The Basic Approach*

The method used to evaluate the individual TES technologies was to estimate the utility savings associated with each TES system and to compare these savings with the additional capital cost of the TES system over the corresponding conventional system. For space heating applications, the utility savings were estimated by calculating the difference between the utility cost (capital, fuel, and operating) of meeting the conventional direct resistance load and the cost of meeting the storage electric heating load. If the calculated utility savings exceeded the difference between the capital cost of the storage heating system and the conventional heating system, the system was deemed "cost effective." A similar procedure was employed to evaluate storage air conditioning and storage hot water systems.

Because of the wide variation in the variables and conditions affecting the cost-effectiveness of storage heating and storage air conditioning, these TES systems were evaluated for a number of utility service areas. The four service areas for which detailed results are presented were selected to illustrate the important factors affecting the cost-effectiveness of the individual types of systems.

3.2.2 *Accounting Framework and Method*

Under the accounting method used in the study, both capital and fuel costs were expressed in annualized values. Except for differences due to different equipment lifetimes, the utility capital cost savings and the storage system capital costs were calculated on the basis of the same capital charge rate. The effect was to value units of capital on either side of the electric meter equally.* Because capital charge rates representative of recent utility experience were used, the accounting procedure was conceptually equivalent to assuming utility ownership of the storage system, although in practice this need not be the case and, from the point of view of the utility, may not be desirable. Levelized annual utility fuel savings were computed on the basis of the same discount (cost-of-money) factor used in estimating annual capital costs.

3.2.3 Utility Cost Savings

The most difficult part of the analysis is estimating the utility savings associated with the introduction of the TES systems. The utility savings are sensitive to the utility's seasonal and daily load profiles, to seasonal weather patterns, and to the level of TES market penetration.

A survey of utility cost-of-service models conducted at the beginning of the project indicated that none of the available models could easily be adapted to the problem of assessing customer TES systems. Consequently, SIMSTOR, a computer simulation model, was developed to calculate the utility costs of meeting conventional and TES loads.

SIMSTOR uses hourly load and tri-hourly weather data and TES and conventional system performance characteristics to generate load profiles over a full annual (8760 hour) cycle. It then calculates the incremental utility capital and fuel costs to meet the incremental loads. SIMSTOR incorporates a load dispatch model and observes operating constraints such as scheduled and forced outages and the cycle time of each type of generating unit. It calculates transmission and distribution costs as well as generating costs.

3.2.4 Storage System Cost/Performance Data

Cost/performance data for TES systems were obtained from a number of sources. For commercially available systems, these sources included manufacturers, sales representatives, distributors, and retailers, and, for advanced systems, engineering-research groups.

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*Justification for this procedure is given in Sec. 3.3.1

In characterizing electric storage heating systems, the study relied heavily on data for commercially available European systems. Data for storage hot water heaters were obtained primarily from U.S. manufacturers and retailers. Because there are no commercially available TES space-cooling systems, cost/performance estimates were developed from data for systems either in the development or test phases.

3.2.5 Case Study Approach

A "case study" approach was adopted to evaluate the cost-effectiveness of individual TES technologies. The case studies amounted to the evaluation of three specific TES systems within four electric utility service areas. The service areas were selected to effectively span the range of variation of those utility variables and climate conditions likely to influence the cost-effectiveness of the TES systems. In each service area the TES systems were matched to the requirements of a 1500 ft^2, well insulated, detached, single family dwelling unit.

3.2.6 Savings and Cost Relationships

The analysis of TES systems must take into account the dependence of the TES benefits on the levels of market penetration. The utility's average savings per TES installation generally decrease as the number of installations increases. On the other hand, the TES cost per installation, except for very small numbers of TES customers, is approximately constant, independent of the number of installations. The behavior of the utility savings and TES cost functions implies the existence of an optimum TES ownership-saturation level, corresponding to the point of maximum *net* savings.

The relationships among total, average, and marginal savings and costs are illustrated in Fig. 3.1. The point N*, defined in Fig. 3.1 (c) as the point of intersection of the marginal benefit and marginal cost curves, represents the optimum number of customers for the particular TES system and service area. In practice, the presence of a market saturation barrier -- at point N_s in Fig. 3.1 (a) -- may prevent the achievement of the maximum net savings. For example, once storage space heating installations reach 100% of total electric space heating installations, further savings are limited by the rate of growth of the electric space heating market.

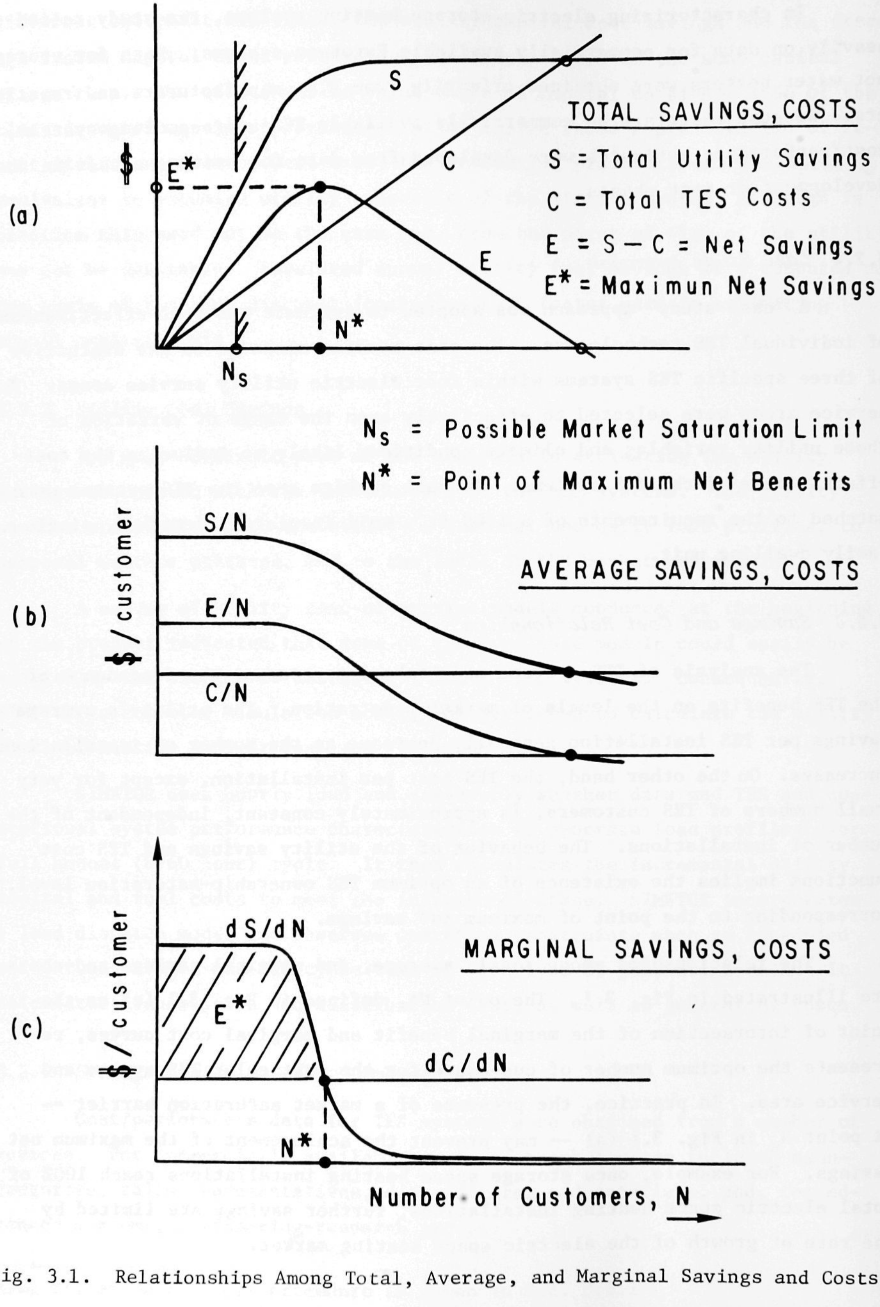

Fig. 3.1. Relationships Among Total, Average, and Marginal Savings and Costs

The dependence of average utility savings on TES market penetration means that utility savings and TES costs cannot be compared without reference to the number of TES installations. Accordingly, the savings and cost estimates given in Chapter 5 correspond to points $N = 1$, N_s, and N^* in Fig. 3.1.

3.2.7 Assumptions and Limitations

A number of simplifying assumptions are implicit in the methodology adapted to analyze the cost-effectiveness of the TES systems:

Each type of TES system was analyzed independently and separately. Although electric utilities that promote the installation of storage space heating are also likely to promote storage hot water heating, neither this nor other possible combinations of TES systems were evaluated. The justification for treating TES systems separately is that it greatly simplifies the analysis while still permitting comparisons of the "stand alone" benefits of the individual technologies.

The model used to calculate utility savings, SIMSTOR, is a static equilibrium model. The introduction of a new technology is inherently a dynamic process; however, the estimation of such conditions and variables as rates of market penetration, changes in electric utility load curves, and changes in fuel and capital prices is exceedingly difficult and probably beyond the present state of forecasting art.

The method adopted by this study was to simulate the performance of the individual TES systems within existing utility supply systems and to ask whether the systems were cost-competitive *at the margin* in meeting changes in today's load curves. In these analyses, utility fuel and capital and TES capital were valued at today's prices. To the extent that future utility fuel and capital prices rise more rapidly than TES capital prices, the effect of the study's implicit price assumptions is to underestimate the net savings from TES.

Only residential applications of TES were evaluated. Although commercial and industrial applications can offer significant advantages, particularly unit cost reductions through scale economies and better duty cycles through load diversity, the first phase of the study was limited to evaluations of TES applications within the residential market. Subsequent phases will examine TES applications in the commercial and industrial markets.

3.3 *COMMERCIALIZATION STRATEGIES ANALYSIS*

3.3.1 *The Electricity Market*

The problem of commercializing a particular thermal storage technology was considered separately from the problem of determining its cost-effectiveness. This approach distinguishes between the separate issues of *desirability* and *feasibility* of commercial introduction of the technology. The distinction is important because of the nature of the electricity market.

Under the conventional wisdom, electric power companies are conceived as "natural monopolies" and, as a consequence, state governments have granted them exclusive geographical franchises in return for regulatory control over their rates. Within this framework, in principle, it is possible to commercialize virtually any storage technology. All that is required is the introduction of electric rates so advantageous to customers with storage equipment, or so disadvantageous to those without, that the opportunity cost of foregoing storage is prohibitive.

The nature of the commercialization problem suggests that the assessment of the net social benefits of customer TES should precede (in both the conceptual and the practical sense) the consideration of any strategies to commercialize it. A corollary condition on the adoption of this "social accounting" framework is that equal resource units be valued equally on either side of the electric meter.

3.3.2 *Customer Behavior*

Individual customers can be expected to install TES systems if the utility transfers enough of its storage-related benefits to make it appear worthwhile for them to do so. Accordingly, the study examined the feasibility of four basic mechanisms for providing the necessary customer incentives to install each type of TES system. The four methods, each of which requires utility support and regulatory approval, are:

- Introduction of time-of-use rate schedules,
- Introduction of demand charges,
- Offering of load management contracts, and
- Utility ownership of the TES systems.

For the individual customer, each method offers a different set of benefits, risks, and information costs, and, for the utility, each method entails a different set of technical and management requirements.

for the individual customer, each entails different [illegible] risks, and interruption costs, and, for the utility, [illegible] different set of technical and management requirements.

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3.4.3 [illegible]

Individual customers [illegible] expected to install TES systems if the utility [illegible] storage-related [illegible] to make it [illegible] worthwhile [illegible] Accordingly, the study examined the feasibility of [illegible] by the utility [illegible] incentives to install [illegible] four methods, each of which requires [illegible]

* Introduction of [illegible]
* Introduction of [illegible]
* Offering of [illegible]
* Utility ownership [illegible]

4. *CASE STUDIES*

4.1 *INTRODUCTION*

This chapter describes the case studies of the cost-effectiveness of individual TES technologies. The case studies amounted to the evaluation of specific TES systems within four utility service areas; the service areas were selected to provide a cross section of those variables and conditions likely to affect the cost-effectiveness of several of the more promising TES systems.

The method adopted to evaluate the TES systems was to calculate the utility costs of meeting conventional and TES loads for a "design year" for each service area and then to compare the difference in utility costs with the additional capital cost of the TES system over the conventional system. The year 1973 was selected for evaluation because it represented the most recent year, except 1974, for which chronological load and weather data were readily available. The year 1974 was rejected because load data for that year exhibit the effects of a severely contracting economy and of temporary post-embargo consumer conservation efforts.

Using the quasi-equilibrium model SIMSTOR to calculate utility savings is equivalent to estimating the difference in the long-run marginal costs of meeting conventional and TES loads. Because the method does not incorporate a forecast of future load curves, it does not directly address the question of TES impact on future supply costs for *specific* electric utilities. However, it does estimate TES unit savings for utilities expecting to face seasonal and daily load shapes similar to those of the utilities actually examined.

4.2 *DESCRIPTION OF SERVICE AREAS AND UTILITY SYSTEMS*

Four utility service areas were selected for the evaluation of the TES systems. The average daily load curves for each area are given in Figs. 4.1 through 4.4; these curves were calculated using hourly load data obtained directly from the individual utilities. Summary statistics describing the four service areas are displayed in Table 4.1. Service Areas A and B, serviced by winter-peaking utilities, represent potential markets for electric storage heating systems, and Service Areas C and D, potential markets for storage air conditioning.

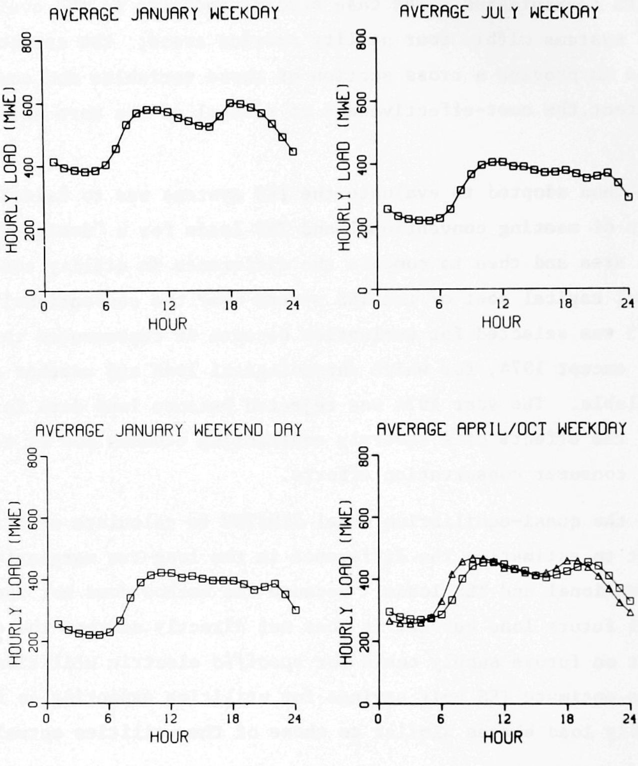

Fig. 4.1. Average Daily Load Curves, Service Area A

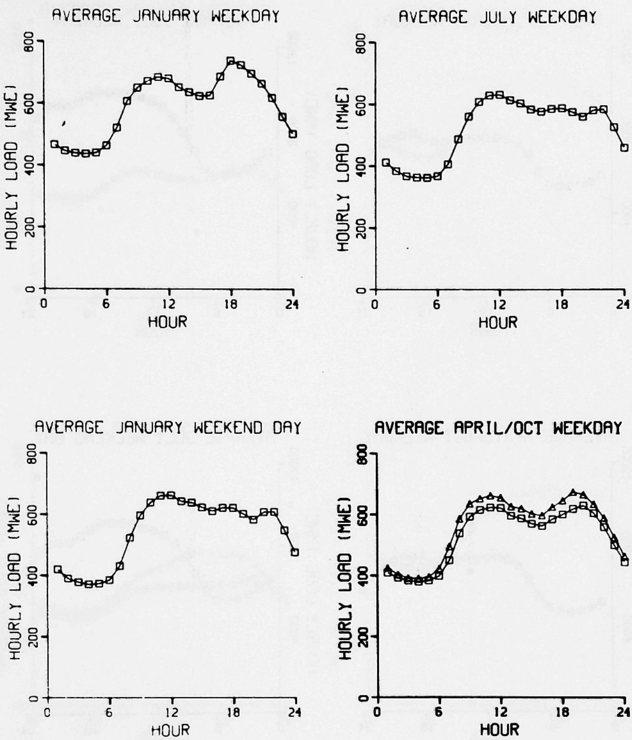

Fig. 4.2. Average Daily Load Curves, Service Area B

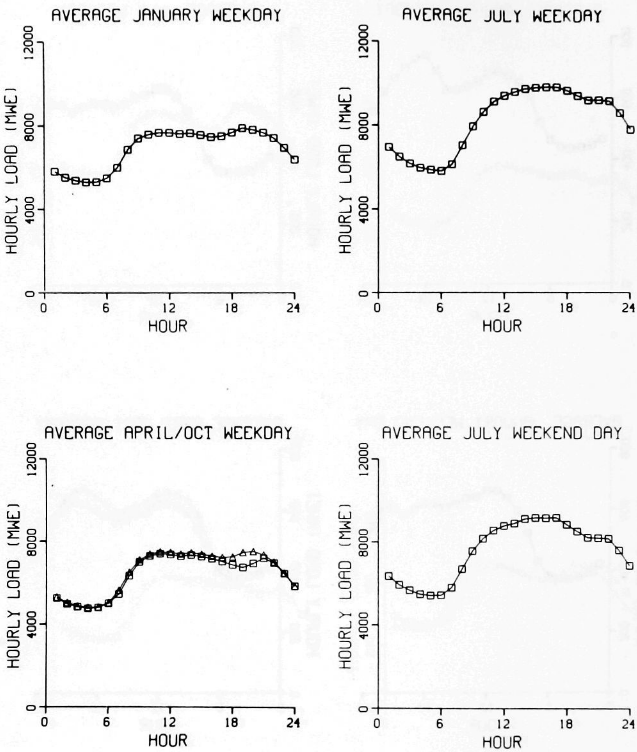

Fig. 4.3. Average Daily Load Curves, Service Area C

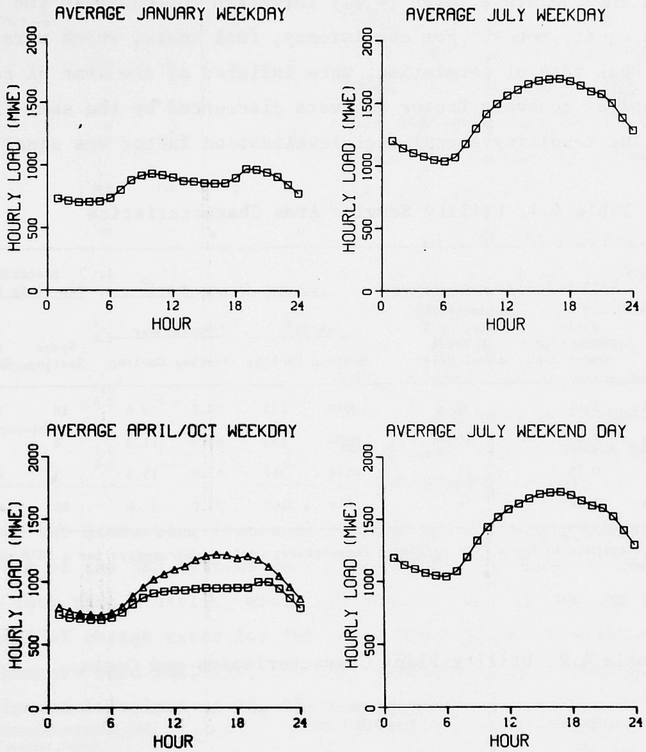

Fig. 4.4. Average Daily Load Curves, Service Area D

The utility parameters and cost inputs to the SIMSTOR calculations are given in Tables 4.2 and 4.3. The generating plant-type mixes in Table 4.3 refer to new plant (being added at the margin) in each of the four service areas. The capital recovery factors correspond to current utility accounting practices and incorporate a large (≈ 6%) inflation component in the cost of both bond and equity money. For consistency, fuel costs, which were assumed to have a 0% real rate of escalation, were inflated at the same 6% rate implicit in the capital recovery factor and were discounted by the same (11%) discount rate. The resulting annual fuel levelization factor was equal to 1.77.

Table 4.1. Utility Service Area Characteristics

		Utility Load Characteristics		Climate (degree-days)[a]				Electric Appliance Ownership Saturation (%)		
				Annual		Design-day				
Service Area	Location	Ratio: Winter to Summer Peak	Residential Sales as % of Total Annual Sales	Heating	Cooling	Heating	Cooling	Space Heating	Air Cond.	Water Heaters
A	Northeast	1.44	37	7010	233	72.0	10.6	10	10	53
B	Northeast	1.13	40	6904	153	65.0	11.0	4	5	20
C	Midwest	0.75	27	6114	317	65.0	15.3	3	47	10
D	Southwest	0.585	29	1419	3162	23.0	31.6	20	40	17

[a]Heating degree-days calculated for a 65°F reference temperature; cooling degree-days for a 70°F reference temperature.

Table 4.2. Utility Plant Characteristics and Costs

	System Costs				Accounting Factors		Unit Operating Characteristics					
Plant Type	Capital (\$/kW)	Fuel (\$/MWh)	Operating (\$/MWh)	Fuel (¢/10^6Btu)	C.C.I.F.[a]	Capital Recovery Factor (%)	Heat Rate (Btu/kWh)	Scheduled Outage (weeks/yr)	Forced Outage Rate (%)	Minimum Cycle Time (hrs)	Cycling Costs (\$/cycle /MW)	Minimum Operate Load (%)
Base												
Nuclear	450	5	1	50	1.44	17	10,000	9	11	12	72	40
Coal	350	9.5	1	100	1.37	17	9,500	5	8	12	126	40
Intermediate												
Coal	300	12	2	100	1.25	17	12,000	5	8	6	35	30
Combined Cycle	250	17	3	205	1.12	17	8,300	4	4	6	70	30
Peak												
Gas Turbine	150	31	5	220	1.05	20	14,000	4	9	1	20	30
Transmission	150	--	-	--	1.00	17	---	-	-	-	--	--
Distribution[b]												
Primary	100	--	-	--	1.00	17	---	-	-	-	--	--
Secondary	100	--	-	--	1.00	17	---	-	-	-	--	--

[a]Construction Compound Interest Factor

[b]For Utility C, which represents a compact urban service area, these values were reduced by 10%

Table 4.3. Utility System Characteristics

	Utility Service Area			
	A	B	C	D
Generating Plant Type (%)				
Base				
Nuclear	100	100	50	25
Coal	0	0	50	75
Intermediate				
Coal	0	0	75	75
Combined Cycle	100	100	25	25
Peaking				
Gas Turbine	100	100	100	100
Reserve Margin %	20	20	15	18
T & D Loss Factors (%)	11	11	8	15
Transmission				
Line	5.1	3.3	2.0	6.0
Core	0.5	0.5	0.5	0.5
Distribution-Primary				
Line	2.0	3.0	2.0	3.3
Core	0.5	0.5	0.5	0.5
Distribution-Secondary				
Line	2.0	3.1	2.5	3.1
Core	0.5	0.5	0.5	0.5

4.3 DESCRIPTION OF TES SYSTEMS

4.3.1 Introduction

Specific TES system designs were selected for each of the three categories of TES applications examined under Phase 1 of the study. The characteristics and costs of the TES and conventional systems are summarized in Tables 4.4, 4.5, and 4.6.

In each service area, each TES system was sized to the local design-day requirements of the same standard house. The standard house -- a 1500 ft^2, detached, single-family dwelling unit -- was well insulated, presenting the utility with a space heating load of 4.0 kWh/degree-day.

Under the accounting framework adopted by the study, the annualized capital costs of the TES systems were computed on the basis of the same capital charge rate that a utility would apply if it were to own the TES system. Thus the capital charge rates for TES space heating, air conditioning, and hot water heaters were 20%, 23%, and 25%, respectively, corresponding to expected equipment lifetimes of 20, 15, and 10 years.

4.3.2 Space Heating Systems

Both dispersed and central-furnace TES space heating systems were selected for evaluation. System storage capacities corresponding to the design-day heating load were estimated for storage durations (discharge periods) of 4, 8, and 16 hours. The storage capacities given in Table 4.4 correspond to energy efficiencies of 100% for the room units and 90% for the basement-located central furnace systems.

The equipment costs of the TES systems are based on cost data for commercially available European systems. Installation costs were estimated from

Table 4.4. Space Heating Systems

Service Area	TES units per Customer	Discharge Period (hrs)	Storage Capacity (kWh)	Power Rating (kW)	Total ($)	TES less Conventional System ($)	TES less Conventional System ($/yr)[a]
	System Characteristics				Capital Cost (installed) per Customer		
A	Conventional Baseboard		--	14	1025	----	---
A	6	4	53	16	2515	1490	298
A	6	8	100	19	3145	2120	424
A	6	16	192	36	4650	3625	725
A	10	4	53	16	3235	2210	442
A	10	8	100	19	3865	2840	568
A	10	16	192	36	5370	4345	869
A	Conventional Central Furnace		--	16	1120	----	---
A	1	4	58	17	2115	995	199
A	1	8	110	21	2810	1690	338
A	1	16	211	40	4460	3340	668
B,C	Conventional Baseboard		--	13	950	----	---
B,C	6	4	48	14	2420	1420	294
B,C	6	8	90	17	2990	2040	408
B,C	6	16	173	33	4345	3395	679
B,C	10	4	48	14	3140	2190	438
B,C	10	8	90	17	3710	2760	552
B,C	10	16	173	33	5065	4115	823
B,C	Conventional Central Furnace		--	14	1085	----	---
B,C	1	4	53	16	2010	925	185
B,C	1	8	99	19	2635	1550	310
B,C	1	16	190	36	4125	3040	608

[a] Based on a capital charge rate of 20% for a 20-year device lifetime. Corresponds to utility accounting practice.

Table 4.5. Central Air Conditioning Systems

Service Area	Discharge Period (hrs)	Storage Capacity (kWh)	Compressor Rating (kW)	Total ($)	TES less Conventional System ($)	TES less Conventional System ($/yr)[a]
	System Characteristics			Capital Cost (installed) per Customer		
C	Conventional Central		3.7	980	----	---
C	4	15	3.3	1680	700	161
C	8	30	4.1	2075	1095	252
C	16	53	8.3	3325	2345	539
D	Conventional Central		4.7	1190	----	---
D	4	20	4.5	2000	810	186
D	8	38	5.6	2520	1330	306
D	16	68	11	4160	2970	683

[a] Based on a capital charge rate of 23% for a 15-year device lifetime. Corresponds to utility accounting practice.

information provided by building contractors, TES and conventional system vendors, and electric utilities. The cost of the TES systems includes the cost of an installed ripple control system.

The daily load profiles used in the SIMSTOR simulations of the three types of storage systems are shown in Fig. 4.5. More detailed information about the data and methods used to size and cost the individual systems is given in Appendix A.

Table 4.6. Domestic Hot Water Systems

System Characteristics			Capital Costs (installed) per Customer		
Service Area	Discharge Period (hrs)	Tank Capacity (gals)	Total ($)	TES less Conventional System ($)	($/yr)[a]
A,B,C,D	Conv'tl	52	165	---	--
A,B,C,D	4	52	270	105	26
A,B,C,D	8	82	365	200	50
A,B,C,D	16	120	485	320	80

[a]Based on a capital charge rate of 25% for a 10-year device lifetime. Corresponds to utility accounting practice.

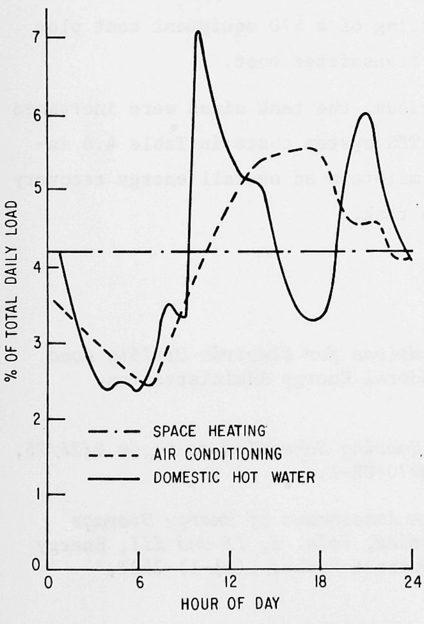

Fig. 4.5. Hourly Conventional-Device Load as Percent of Device Total Daily Load. Air Conditioning Curve Applies Only to Summer Peak Day, Service Area C.

4.3.3 *Air Conditioning Storage*

Because of the inherent scale efficiencies, TES air conditioning will utilize central, rather than dispersed, storage systems. The TES costs given in Table 4.5 are based on a central ice-making system similar to that recently developed by A. O. Smith, Inc.

The two major components raising the cost of the TES system relative to that of the conventional air conditioning system are the cold storage system proper and the larger condenser/compressor unit required to handle the direct night time cooling load plus the charging of the storage system. The equipment cost of the storage unit includes the costs of the ice/water tanks, evaporators, water pump, ice pump, ice sensor, and expansion valve.

The conventional and TES costs given in Table 4.5 are based on a coefficient of performance of 2.2 and a net energy efficiency for the TES system equal to 95% of that of the conventional system. The costs for both the TES and conventional systems include an installation charge equal to 100% of the equipment cost. More details about the costs and performance characteristics of the individual systems are given in Appendix A.

4.3.4 Hot Water Heaters

The incremental costs of a TES hot water heater were calculated relative to those of a conventional 52 gallon hot water tank. This tank, equipped with 4.5 kW heaters, has a recovery rate of about 18 gal/hr (100°F temperature rise) and is considered adequate for a family of three or four.

For the mode of operation corresponding to a four hour discharge (20 hour charging) period, it was assumed that the capacity of the standard tank would be adequate to cover normal domestic usage during the discharge period. Thus, the difference between the TES and the conventional system is the cost of the ripple control installation, consisting of a $70 equipment cost plus 50% for installation and its share of the transmitter cost.

For the 8 and 16 hour discharge periods, the tank sizes were increased to 82 and 120 gallons, respectively. The TES system costs in Table 4.6 include the costs of improved insulation to maintain an overall energy recovery efficiency of 95% of that of the reference tank.

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5. *STUDY FINDINGS*

5.1 *INTRODUCTION*

This chapter summarizes the study findings; it presents the results of the cost-effectiveness analysis, describes alternative strategies for commercializing TES systems, and advances several R&D recommendations.

5.2 *COST-EFFECTIVENESS EVALUATION*

5.2.1 *Overview*

The cost-effectiveness of each of the three TES systems was evaluated within each of the four utility service areas. As expected, for a given TES system, average utility savings per TES installation were found to depend critically upon the shape of the utility's seasonal and daily load curves and upon the level of market penetration.

Utility savings from storage space heating exceeded TES costs in Service Areas A and B. However, because the utility supplying Service Area B is only mildly winter peaking, it quickly encounters a scheduled maintenance constraint as the winter peak loads are reduced. Thus, utility savings in Service Area B are substantially less than in Service Area A.

Storage air conditioning was found to be cost-effective in both of the service areas supplied by summer-peaking utilities. At the market penetration levels providing maximum net benefits for the system characterized by an 8-hour discharge period, the utility savings/TES cost ratio is 1.45 in Service Area C, whereas the ratio is 3.12 in Service Area D.

Storage hot water heating is cost effective in all the service areas examined, the annual utility savings exceeding TES costs by $50-100 per installation for the long discharge-period systems at 100% saturation of the electric hot water heater market.

5.2.2 *Case Study Results*

Tables 5.1, 5.2, 5.3, and 5.4 present the results of the four individual case studies. The tables give average utility savings and TES costs for levels of market penetration corresponding to the first TES installation

Table 5.1. Utility Average Savings, Service Area A

TES System and Discharge Period	Number of TES Customers	Generation Peak Load Reduction		Oil Savings (10^3bbls per year)	Average Utility Savings ($/yr/customer)							TES Cost[c] ($/yr/ Customer)	Total Net Savings (10^6\$/yr)
					Capital			Variable					
		(MW_e)	(% of Peak)		Gen.	Tran.	Dist.	Fuel	O&M	Cycle	Total		
Space Htg.													
4	1	0	0	0	816	551	-48	107	16	8	1,448	442	---
4	5,900[a]	39	5.3	37	405	201	-3	67	11	14	695	442	1.49
8	1	0	0	0	976	551	465	115	18	18	2,144	568	---
8	2,800[a]	40	5.5	33	841	441	-36	127	19	30	1,421	568	2.37
16	1	0	0	0	1,136	551	465	66	11	-3	2,226	869	---
16	2,800[a]	44	6.1	54	892	486	-164	201	30	33	1,478	869	1.69
Water Htg.													
4	1	0	0	0	70	37	11	-13	-2	6	109	26	---
4	50,000[b]	24	3.3	-25	37	15	11	-7	-1	4	58	26	1.61
8	1	0	0	0	96	37	41	-25	-4	8	152	50	---
8	50,000[b]	40	5.5	-6	61	24	3	-2	0	6	92	50	2.11
16	1	0	0	0	150	37	41	-16	-2	12	222	80	---
16	50,000[b]	40	5.5	68	93	24	-14	16	2	11	132	80	2.60

[a]Number of TES customers at which total net benefits are maximized (N=N*).

[b]Number of TES customers at which the aggregate TES design-day kilowatt-hour load equals the aggregate design-day kilowatt-hour load of existing conventional-system customers ($N=N_s$).

[c]From Tables 4.4, 4.5 and 4.6.

Table 5.2. Utility Average Savings, Service Area B

TES System and Discharge Period	Number of TES Customers	Generation Peak Load Reduction		Oil Savings (10^3bbls per year)	Average Utility Savings ($/yr/customer)							TES Cost[c] ($/yr/ Customer)	Total Net Savings (10^6\$/yr)
					Capital			Variable					
		(MW_e)	(% of Peak)		Gen.	Tran.	Dist.	Fuel	O&M	Cycle	Total		
Space Htg.													
4	1	0	0	0	254	0	-132	394	58	31	605	438	---
4	4,600[a]	27	2.8	11	454	182	-44	32	5	21	650	438	0.98
8	1	0	0	0	462	0	354	124	19	25	984	552	---
8	5,800[a]	41	4.3	-33	686	217	-94	-46	-7	38	794	552	1.40
16	1	0	0	0	635	0	442	244	36	32	1,390	823	---
16	1,500[a]	11	1.2	7	851	232	199	64	10	16	1,373	823	0.85
Water Htg.													
4	1	0	0	0	112	41	22	-32	-5	11	148	26	---
4	34,400[a]	41	4.3	-4	68	36	12	-5	-1	4	114	26	3.02
8	1	0	0	0	173	45	32	-36	-5	6	215	50	---
8	34,400[a]	42	4.4	-10	85	38	5	-6	-1	5	125	50	2.59
16	1	0	0	0	162	49	44	-16	-3	1	237	80	---
16	37,500[b]	46	4.8	-47	161	37	-9	-8	-1	10	190	80	4.13

[a]Number of TES customers at which total net benefits are maximized (N=N*).

[b]Number of TES customers at which the aggregate TES design-day kilowatt-hour load equals the aggregate design-day kilowatt-hour load of existing conventional-system customers ($N=N_s$).

[c]From Tables 4.4, 4.5, and 4.6.

Table 5.3. Utility Average Savings, Service Area C

TES System and Discharge Period	Number of TES Customers	Generation Peak Load Reduction (MW_e)	(% of Peak)	Oil Savings (10^3 bbls per year)	Average Utility Savings ($/yr/customer) Capital: Gen.	Tran.	Dist.	Variable: Fuel	O&M	Cycle	Total	TES Cost[c] ($/yr/ Customer)	Total Net Savings ($10^6$$/yr)
Space Htg.													
4	1	0	0	0	167	0	0	-177	-31	18	-23	438	---
4	54,000[b]	0	0	-560	124	0	0	-115	-20	29	19	438	-22.6
8	1	0	0	0	338	0	0	-254	-41	22	65	552	---
8	54,000[b]	0	0	-448	220	0	0	-136	-23	40	101	552	-24.4
16	1	0	0	0	431	0	0	-322	-52	4	62	823	---
16	54,000[b]	0	0	-224	300	0	0	-120	-20	45	205	823	-33.3
Air Cond.													
4	1	0	0	2	174	138	34	19	4	1	369	161	---
4	397,000[a]	979	8.0	975	93	72	27	21	4	1	218	161	22.5
8	1	0	0	3	175	138	131	31	6	1	483	252	---
8	219,000[a]	945	7.7	791	163	127	35	32	6	1	365	252	24.7
16	1	0	0	4	179	138	134	39	7	1	498	539	---
16	---	---	---	---	---	---	---	--	-	-	---	---	---
Water Htg.													
4	1	0	0	-2	40	24	-10	-10	-2	2	45	26	---
4	145,000[b]	114	0.9	-175	40	23	-10	-9	-2	5	48	26	3.08
8	1	0	0	-4	51	24	17	-26	-3	4	68	50	---
8	145,000[b]	114	0.9	-373	56	23	17	-19	-3	5	79	50	4.21
16	1	0	0	-6	112	24	17	-55	-8	3	93	80	---
16	145,000[b]	114	0.9	-265	108	23	20	-24	-4	8	131	80	7.4

[a] Number of TES customers at which total net benefits are maximized (N=N*).

[b] Number of TES customers at which the aggregate TES design-day kilowatt-hour load equals the aggregate design-day kilowatt-hour load of existing conventional-system customers ($N=N_s$).

[c] From Tables 4.4, 4.5, and 4.6.

Table 5.4. Utility Average Savings, Service Area D

TES System and Discharge Period	Number of TES Customers	Generation Peak Load Reduction (MW_e)	(% of Peak)	Oil Savings (10^3 bbls per year)	Average Utility Savings ($/yr/customer) Capital: Gen.	Tran.	Dist.	Variable: Fuel	O&M	Cycle	Total	TES Cost[c] ($/yr/ Customer)	Total Net Savings ($10^6$$/yr)
Air Cond.													
4	1	0	0	0	339	250	219	93	17	19	937	186	---
4	53,200[a]	158	8.4	243	139	90	79	60	11	14	392	186	11.0
8	1	0	0	0	378	250	219	127	23	27	1,023	305	---
8	18,300[a]	141	7.5	162	355	234	198	121	22	21	950	305	11.8
16	1	0	0	0	382	290	219	191	35	45	1,162	683	---
16	25,100[a]	198	10.5	300	269	238	200	161	29	31	928	683	6.14
Water Htg.													
4	1	0	0	0	41	35	23	26	5	10	140	26	---
4	28,100[b]	29	1.5	17	47	31	22	2	0	8	127	26	2.83
8	1	0	0	0	56	41	30	38	8	12	184	50	---
8	28,100[b]	29	1.5	35	49	32	22	16	5	9	133	50	2.35
16	1	0	0	0	55	41	29	60	10	21	216	80	---
16	28,100[b]	29	1.5	45	72	32	22	31	6	17	180	80	2.81

[a] Number of TES customers at which total net benefits are maximized (N=N*).

[b] Number of TES customers at which the aggregate TES design-day kilowatt-hour load equals the aggregate design-day kilowatt-hour load of existing conventional-system customers ($N=N_s$).

[c] From Tables 4.4, 4.5 and 4.6.

(N = 1) and corresponding to either the optimal penetration level (N = N*) or to the market saturation level ($N = N_s$), whichever is lower.* Market saturation was defined as the number of TES customers at which aggregate TES load on the peak day was equal to the 1973 conventional-system peak-day load.

Storage Space Heating

As shown in Tables 5.1 and 5.2, storage space heating is cost-effective in both of the service areas supplied by winter-peaking utilities. In both service areas, the systems having 8-hour discharge periods achieve the greatest net savings at the market penetrations yielding maximum net savings (N = N*).

The TES costs for space heating systems presented in Tables 5.1 and 5.2 refer to 10-unit dispersed systems. The 10-unit system represents the upper limit on TES costs for the 1500 ft^2 house. Even for this most expensive TES system, average utility savings exceed average TES costs in Service Area A by a factor of 3.8 for the first 8-hour system installed and by a factor of 2.5 for the 2,800th system installed. Figure 5.1 illustrates the dependence of marginal utility savings on market penetration for storage space heating systems having 4-, 8-, and 16-hour discharge periods. (Similar plots for other TES systems and for other service areas are given in Appendix B.)

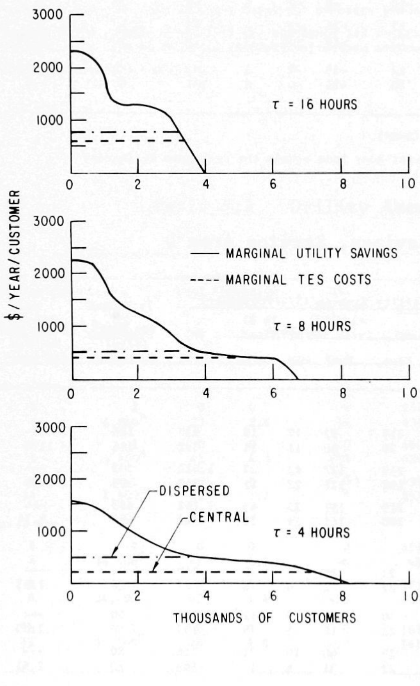


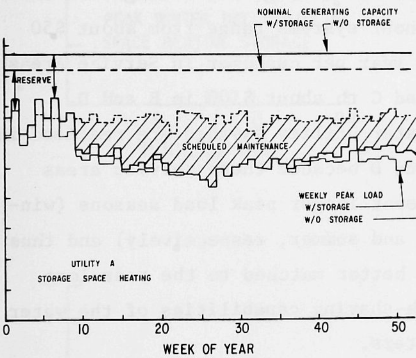
Fig. 5.1. Storage Space Heating in Service Area A: Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

In Service Area A, transmission plant capital savings are about one-half generating plant capital savings. Distribution plant savings are generally negative, increasing in magnitude

See Fig. 3.1, page 22, for definitions of N and N_s.

as more systems are attached and as the storage discharge period increases. The longer discharge periods imply shorter charging periods which, because of the magnitude of the space heating load, create nighttime peaks in the utility's distribution network.

The net benefits of storage space heating are generally lower in Service Area B than in Service Area A. As indicated in Fig. 5.2, Service Area B is scheduled-maintenance constrained, so that reductions in winter peak loads do not translate directly into equivalent capacity savings. Nevertheless, at the point of maximum net savings, utility savings exceed TES costs by more than 40%, even for the 10-unit dispersed TES system.



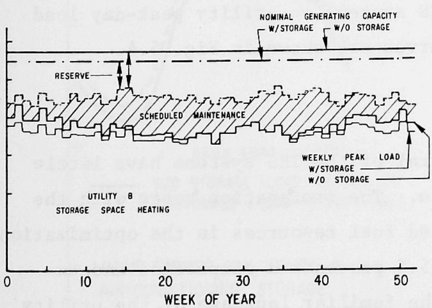


Fig. 5.2. Effect of Customer TES on Utility Weekly Peak Loads, Service Areas A and B.

As expected, storage space heating is not cost-effective in Service Area C, the reduction in winter peak loads not affecting the overall peak-capacity requirements of this summer-peaking utility.

Storage Air Conditioning

Storage air conditioning was found to be cost-effective in both of the service areas supplied by summer-peaking utilities. The savings are especially large in Service Area D, owing mainly to the long air conditioning season. In this service area, average utility savings exceed TES costs by about \$650 per year per installation for the system and market penetration level yielding maximum total net savings.

In both service areas, storage air conditioning systems having 8-hour discharge periods provide the largest net savings. As indicated in Fig. 5.3,

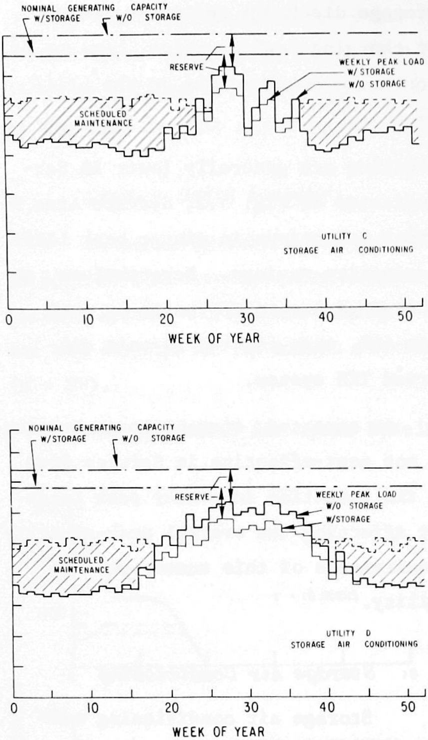


Fig. 5.3. Effect of Customer TES on Utility Weekly Peak Loads, Service Areas C and D.

neither utility encounters a scheduled maintenance problem at market penetrations of the 8-hour systems yielding maximum net benefits.

Storage Hot Water Heaters

Storage hot water heaters are cost-effective in all the service areas examined. Total net savings generally increase as the discharge period increases. Average net savings for the 16-hour systems range from about $50 per year per customer in Service Areas A and C to about $100 in B and D. Greater utility savings are realized in B and D because these service areas present longer peak load seasons (winter and summer, respectively) and thus are better matched to the year-long peak-shaving capabilities of the water heaters.

The effect of several customer TES systems on utility peak-day load curves are shown in Fig. 5.4.

5.2.3 *Oil Savings*

An unexpected finding is that several of the TES systems have little effect on *long-run* utility oil consumption. The explanation rests with the nature of the trade-off between capital and fuel resources in the optimization of utility generating plant mix. Figure 5.5 presents a simplified and exaggerated illustration of the effect in the familiar language of the utility load duration curve. The vertical line HH represents the demarcation between most efficient use of oil-fired peaking and intermediate plant and coal-fired base load plant. The intersection of HH with the load duration curve determines the long-run optimum capacity and output of each of the two types of

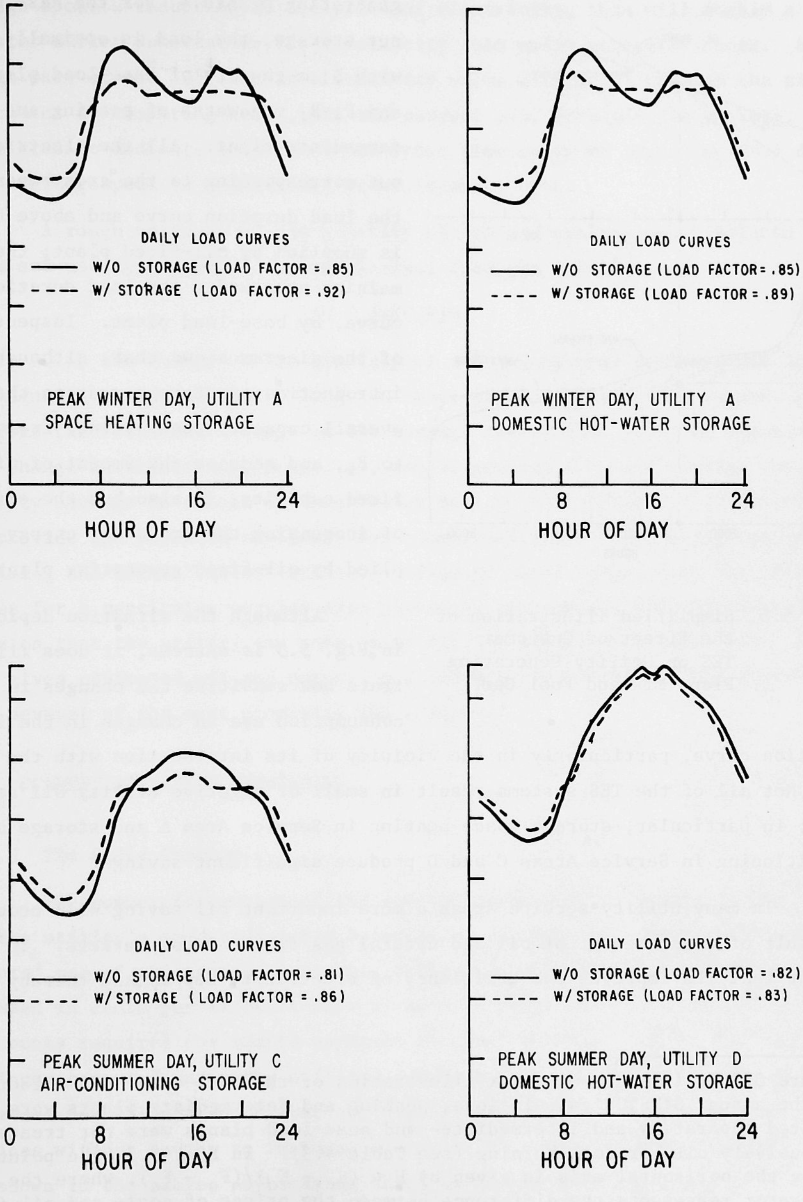


Fig. 5.4. Effect of Customer TES on Utility Peak-Day Load Curves, Service Areas A, B, C, and D

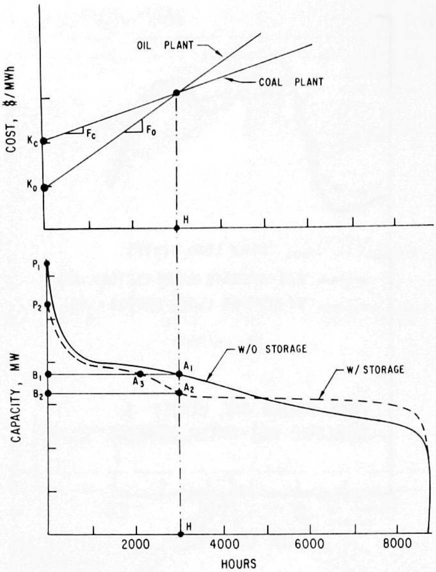


Fig. 5.5. Simplified Illustration of the Effect of Customer TES on Utility Generating Plant Mix and Fuel Use.

generating plants.* For the case without storage, the load is optimally met with B_1 megawatts of base-load plant and P_1-B_1 megawatts of peaking and intermediate plant. All the electric output corresponding to the area beneath the load duration curve and above B_1A_1 is supplied by oil-fired plant; the remaining area under the load duration curve, by base-load plant. Inspection of the diagram shows that, although the introduction of storage reduces the overall capacity requirement, from P_1 to P_2, and reduces the amount of oil-fired capacity, it also has the effect of increasing the amount of energy supplied by oil-fired generating plant.

Although the situation depicted in Fig. 5.5 is extreme, it does illustrate how sensitive the changes in oil consumption are to changes in the load duration curve, particularly in the vicinity of its intersection with the line HH. Not all of the TES systems result in small or negative utility oil savings; in particular, storage space heating in Service Area A and storage air conditioning in Service Areas C and D produce significant savings.

In many utility service areas a more important oil saving will occur as a result of displacement of oil and natural gas from end-use markets. To the extent that TES improves the efficiency of electricity supply,and thereby

*Figure 5.5 is intended only for illustration of the fuel trade-off effect. In the actual SIMSTOR calculations, peaking and intermediate plants were treated separately and intermediate- and base-load plants were not treated as exclusively oil- or coal-burning (see Table 4.3). In Fig. 5.5, the point H along the horizontal axis is given by $H = (K_c - K_o)/(F_o - F_c)$, where the numerator represents the difference between the prices of coal- and oil-fired capacity ($/MW) and the denominator, the difference between the present worth of the costs of oil and coal ($/MWh) over the plant lifetimes.

brings about a reduction in the price of electricity, this will enable a greater market penetration for electricity than would otherwise occur. A large part of the increase in electricity sales will occur through the displacement of competing fuels, oil and natural gas, from end-use markets. Recent studies indicate that the cross-price elasticity of competing-fuel demand with respect to electricity price is about 0.44.

A rough estimate of the quantity of oil and natural gas displaced from end-use applications can be obtained from the relation

$$\Delta Q = \beta(\Delta P/P)Q$$

where ΔQ is the change in the quantity of oil and natural gas consumed in the residential market, β is the long-run cross price elasticity of demand, and $\Delta P/P$ is the fractional change in the average residential price of electricity. The change in electricity price, ΔP, can be estimated by determining the utility savings in excess of those which must be transferred to TES customers to provide the paybacks necessary for commercialization of the TES systems. Dividing the total "excess" utility savings by total residential electricity sales for a particular service area gives the average electricity price reduction that the utility can pass on to all its residential customers. Table 5.5 gives estimated oil and natural gas savings (in barrels of oil equivalent) for several of the most promising TES systems.

5.3 *COMMERCIALIZATION STRATEGIES*

5.3.1 *The Basic Problem*

The commercialization of TES systems depends upon transferring enough of the utility's storage-related benefits to customers to justify the customers' use of the storage devices. Table 5.6 compares utility savings, expressed in cents per kilowatt-hour of device energy use, with the energy-price discounts required for simple paybacks of three and five years. The utility savings, computed under the utility accounting method, represent the maximum revenues per kilowatt-hour that the utility can transfer to purchasers of TES devices without having to increase the price of energy to other customers. As shown in the table, paybacks as short as three years can be offered for all the TES systems, with the exception of storage space heating in Service Area B.

Table 5.5. TES-Induced Oil and Gas Savings, Residential Market

Service Area	TES System	Discharge Period (hrs)	Residential Oil and Gas Consumption (10^6 bbls/yr, equiv.)	Utility Oil Savings (10^3 bbls/yr)	3-Year TES Payback: $(\Delta P/P)$[a]	3-Year TES Payback: End-Use Oil Savings[b] (10^3 bbls per yr)	3-Year TES Payback: Total Oil Savings (10^3 bbls per yr)	5-Year TES Payback: $(\Delta P/P)$[a]	5-Year TES Payback: End-Use Oil Savings (10^3 bbls per yr)	5-Year TES Payback: Total Oil Savings (10^3 bbls per yr)
A	Water Htg.	4	3.84	-25	-0.026	45	20	-0.043	72	47
A	Water Htg.	16	3.84	68	-0.029	49	117	-0.078	132	200
A	Space Htg.	8	3.84	33	-0.030	52	85	-0.055	93	126
B	Water Htg.	4	4.02	-4	-0.073	129	125	-0.085	152	148
B	Water Htg.	16	4.02	-47	-0.083	148	101	-0.126	224	177
B	Space Htg.	8	4.02	-33	---	---	-33	-0.038	66	33
C	Water Htg.	4	66.54	-175	-0.004	106	-69	-0.008	219	49
C	Water Htg.	16	66.54	-265	-0.007	195	-70	-0.019	544	279
C	Air Cond.	8	66.54	791	---	---	791	-0.061	1791	2582
D	Water Htg.	4	2.85	17	-0.023	29	46	-0.028	34	51
D	Water Htg.	16	2.85	45	-0.022	28	73	-0.036	44	89
D	Air Cond.	8	2.85	162	-0.101	127	289	-0.136	172	334

[a]The quantity $\Delta P/P$ represents fractional change in electricity price. The change in price, ΔP, is determined by first calculating utility "excess benefits," that is, those benefits in excess of the savings that must be transferred to TES customers to provide required payback. The excess benefits are then divided by total residential sales to obtain ΔP.

[b]End-use oil savings are estimated from the relation $\Delta Q = \beta(\Delta P/P)Q$ where ΔQ is the reduction in oil and gas sales and β is the cross price elasticity of demand with respect to electricity price. Here, $\beta = 0.44$.

Table 5.6. Utility Savings versus Customer Payback Requirements

Service Area	TES System	Discharge Period[a] (hrs)	Annual Consumption (kWh)	Utility Savings[b] (¢/kWh)	TES Incremental Cost ($)	Payback Required to Commercialize[c] 3-Year ($/yr)	3-Year (¢/kWh)	5-Year ($/yr)	5-Year (¢/kWh)
A	Water Htg.	4	5,840	1.0	105	35	0.6	21	0.4
A	Water Htg.	16	5,840	2.3	320	107	1.8	64	1.1
A	Space Htg.	8	28,000	5.1	2,840	946	3.4	568	2.0
B	Water Htg.	4	5,840	2.0	105	35	0.6	21	0.4
B	Water Htg.	16	5,840	3.3	320	107	1.8	64	1.1
B	Space Htg.	8	27,600	2.9	2,760	945	3.4	552	2.0
C	Water Htg.	4	5,840	0.8	105	35	0.6	21	0.4
C	Water Htg.	16	5,840	2.2	320	107	1.8	64	1.1
C	Air Cond.	8	2,500	14.6	1,095	365	14.6	219	8.8
D	Water Htg.	4	5,840	1.9	105	35	0.6	21	0.4
D	Water Htg.	16	5,840	3.1	320	107	1.8	64	1.1
D	Air Cond.	8	6,500	14.6	1,325	442	6.9	265	4.1

[a]Discharge periods for air conditioning and space heating systems correspond to devices in Table 1.1. For storage hot water heaters, the 16-hour system offers the greatest net benefits; the 4-hour system is included because it is the easiest to commercialize.

[b]Utility savings per kWh calculated from annual consumption column and from annual utility savings in Table 1.1.

[c]Simple payback; does not include cost of capital.

The existence of large potential savings and the ability to offer short paybacks, are not, however, of themselves sufficient to guarantee commercial success of TES technologies. In particular, the mechanism for transferring the benefits to customers must be reasonably efficient and must be perceived by customers as fair. Given the large potential savings, relative to costs, of several of the storage systems, the utility may find it necessary to pass some of the storage-related benefits to non-storage customers. This may be the only way that the utility can avoid complaints by its customers of unfair pricing and by sellers of competing fuels of unfair competition. In addition, the utility must regard the overall benefits achievable by the introduction of storage as worth the administrative bother. For example, in the case of storage hot water heating, although the *relative* savings per installation are large, the overall savings are small. For the utility supplying Service Area C to reduce its peak by 114,000 kW, or 0.9%, it would have to control 145,000 water heaters. In this case, it is possible that the utility may not regard the savings as worth the effort.

Utility concern over the administrative problems and the regulatory issues raised by customer TES may, in fact, be the biggest obstacle to TES commercialization. Unfortunately, this problem is not really amenable to outside solution. However, utilities concerned about the welfare of their customers, and under pressure by regulators to control costs, are likely to support customer TES once they are convinced of its benefits. If the European experience is any guide, utility support will be the crucial element in commercialization of customer TES in the United States.

5.3.2 Alternative Strategies

There are four basic strategies for commercializing customer TES:

- Introduction of time-of-use rate schedules,
- Introduction of demand charges,
- Offering of load management contracts, and
- Utility ownership of the TES systems.

Time-of-Use Rate Schedules

Time-of-use rate schedules involve a relatively high charge on consumption during peak-load periods and much lower rates during off-peak periods.

Table 5.7. Wisconsin Electric Power Co. Proposed Time-of-Use Tariff

Time & Amount of Use	Summer (July-Aug-Sept) (¢/kWh)	Winter (Jan-Feb-Mar) (¢/kWh)	Base (all other months) (¢/kWh)
High Use Hours[a]			
First 500 kWh	7.69	5.10	3.71
Over 500 kWh	7.69	4.50	3.41
Low Use Hours	0.94	0.94	0.94

[a]High use hours: 7 a.m. - 9 p.m., Monday - Friday, inclusive.

The peak-period rate covers both capital and operating costs; the off-peak rate, only the operating costs of base-load units. In practice, time-of-use tariffs usually involve two or, at most, three daily pricing periods and two or three seasonal periods. Table 5.7 presents a tariff recently proposed by a summer-peaking utility company.

As discussed below, there are two major problems associated with using peak load pricing as the mechanism for commercializing TES systems. The first is a practical problem, stemming from the optional basis on which the rates will probably have to be offered. The second, more fundamental, problem arises from the inability of the rates, as currently designed, to accurately capture the load-leveling benefits of TES systems.

The likelihood of customer resistance to the imposition of universal, mandatory time-of-use tariffs means that the rates probably will be offered first on an optional basis. Unfortunately, the effect of making the rates optional will be to remove the strong *dis*incentive to consume energy during the peak-load hours, and thus to remove an important incentive for the customer to invest in a TES system. If the time-of-use tariff is optional, the effective energy-price penalty of foregoing storage is the difference between the price of energy under the *standard* tariff and the off-peak price under the optional tariff. The peak-period price of energy under the optional tariff does not enter into the customer's decision to purchase a TES system. Thus, for TES users, the offer of an optional time-of-use tariff is no different from the offer of a simple off-peak rate discount.

As indicated in Table 5.6, a substantial off-peak discount will be required to commercialize several of the TES systems. For example, in Service

Area C, a price discount upward of 8.8¢/kWh will be required if the customer is to recover his initial capital outlay in five years or less. Because the utility's standard rate in this service area is currently about 3.7¢/kWh, it is clearly impossible to provide the necessary off-peak discount.

One of the central propositions underlying the design of time-of-use tariffs is that capital as well as energy costs should be recovered through a time-varying charge on energy. On the other hand, as discussed in Sec. 5.2, most of the TES savings take the form of pure demand-related capital savings. Although the theoretical basis for peak load pricing is rigorous, in practice, the design of simple, understandable rates always involves compromises and a number of simplifying assumptions and approximations. In particular, the duration and timing of the seasonal and daily pricing periods, although critical in terms of impact on the commercial feasibility of TES, cannot be defined in a completely rigorous and systematic way.

The level of aggregation inherent in the design of time-of-use rates means that they are often poorly matched to the operating characteristics of TES devices. For example, time-of-use rates, designed on the basis of average household contributions to system coincident peak, do not take into account a number of TES effects. These effects include: the extra distribution capacity required to serve electric storage heating customers when the off-peak charging time is short; the development of a new peak load just after the peak-price period due to the bunching of TES switch-on times; and the encouragement of installation of undersized storage systems supplemented by direct-load systems, where the direct loads would occur only on "worst case" days and would not pay their share of the system peak demand costs.

Demand Charges

Demand charges offer the advantages of inexpensive metering; a simple, easy-to-understand design; and established use in the commercial and industrial markets. The typical rate incorporating a demand charge imposes a charge (specified in $/kW) on peak demand during the current billing period or on a certain percentage of peak demand during a specified number of previous billing periods, whichever is greater. Such rates can provide adequate incentive to commercialize TES where the thermal load is large enough and the demand charge is sufficiently high.

Despite their advantages, demand charge rates appear to work poorly in the residential market. The high power requirements of certain residential appliances, such as clothes dryers and electric ranges, and the inconvenience of planning and controlling these devices' energy use have made demand charges unpopular with residential customers.* Another disadvantage of demand charges is that they are inefficient in the sense of not fully incorporating the time element of cost. While rewarding residential customers with level diurnal loads, they penalize customers with nighttime peaks, even though the cost of supplying the latter may be less. More efficient price signals, incorporating time-varying demand charges, could be designed, but these would suffer many of the disadvantages of time-of-use rates.

Load Management Contract Rates

Load management contract rates between utilities and customers can eliminate many of the problems associated with time-of-use rates and demand charges because they can be tailored to the effect of a TES unit upon the utility system.** The rate contracts can be formal or informal, requiring a separate signed agreement or simply representing an option under the standard rate schedule. In either case, the basic concept underlying the load management contract rate is to provide the customer lower cost electric service in return for some form of utility control over the charging cycle of the device.

The utility can exercise its control through preset clocks attached to the TES devices or through radio or ripple control. Under ripple control, the timing and sequencing of the ripple signals can be set by "hard-wired" logic at the substation transmitter or can be under real-time central control by the utility's load dispatch center. Using a central control system, the utility can manage the storage loads for optimal load-leveling effect.

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*Particularly onerous to residential customers is the cost of a "mistake." The $15 cost of an untimely clothes dryer load is the apocryphal example.

**The difference between load management contract rates, as defined here, and low off-peak rates under optional time-of-use rate schedules is that the latter apply to all devices within the household, while the former can be device-specific. Another difference is that the customer retains control over the operation of the TES device under time-of-use rates, while the utility can exercise control under load management rates.

In addition to allowing TES-specific rates and better control over TES loads, load management contract rates permit a more flexible response by utilities to changing system load profiles. Given an improvement in load characteristics through installation of TES systems, the utility need not readjust rates for all customers. Load contract rates offered to old TES customers can be preserved, thereby enabling these customers to realize their expected paybacks, while the utility simply rations or makes less attractive the load management rates offered to new customers. Although this policy might be objected to on grounds that it treats similar customers differently, actually, it merely indicates that for system purposes there is a real difference among customers based upon time of hookup.

Utility Ownership

Utility ownership of TES systems can be used to commercialize TES in situations where the housing market fails to properly capitalize the life-cycle customer cost savings of TES systems. Given a four-year expected house occupancy and a 10% interest rate, a TES purchaser would require a 33% return on investment in situations where the housing market valued TES and conventional systems equally.* For TES systems for which the utility savings are not adequate to cover such large transfers through the rate mechanism, utility ownership offers an alternative commercialization strategy.

Utility ownership may also represent the only feasible alternative if the customer's required savings per kilowatt-hour are large relative to the standard rate, as for storage air conditioning in Service Areas C and D. Although a large monthly credit could be paid to TES customers, the likelihood of other customers' complaints could be sufficiently great to make this an unattractive alternative. Instead, the utility, by owning and charging for the system, could offer a compensating rate discount that would not appear unfair.

The major disadvantages of utility ownership are: the need for utility capital expenditure, the need to provide for utility access to the TES

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*The reverse side of this situation is that were the market to fully capitalize future customer cost savings, the heavily subsidized home mortgage market would make it less costly for the customer than the utility to own the TES system.

equipment, and the nuisance to the utility of maintaining and servicing the equipment. The need to provide utility access to TES equipment represents a cost, involving many intangibles, which the TES customer will have to bear, while the nuisance value of servicing thousands of TES devices, upon which customers are highly dependent, will belong to the utility.

Although cost-effective TES systems are less capital intensive than the conventional utility supply systems that they displace, utility financing is a far less attractive alternative than customer ownership for utilities facing a cost-of-capital squeeze. One important advantage of customer TES systems, even when utility financed, is the very short installation time of TES systems relative to construction times of utility plants. Customer TES can in principle enter the utility rate base in a matter of weeks, compared with several years for utility generating plant. A further advantage is that the cost of TES systems purchased in quantity by utilities is likely to be considerably lower than the single system cost paid by the individual customer.

5.3.3 Recommended Strategies

As should be clear from the foregoing discussion, the variables and issues affecting the choice of strategy to commercialize customer TES are numerous and complex. No one strategy is likely to be most effective for all devices, in all parts of the country, or over an indefinite length of time. Ideally, a number of strategies will be tried by a number of utilities so that the industry and its regulators can make future decisions and choices on the basis of information rather than on speculation.

In advancing the following recommendations for each type of TES system, we have tried to take into account some of the more obvious practical considerations affecting the feasibility of alternative strategies. Under the criterion of social efficiency, there is little difference between the utility ownership and the load management contract approaches to commercialization (so long as each is administered fairly and efficiently); however, there are a number of practical differences. For example, because of the understandable reluctance of utilities to expose themselves to the problems of TES maintenance and because of the effects of regulatory lag on utilities' ability to raise capital, the load management contract approach is usually the preferred strategy. Thus considerations of practical feasibility, more than theoretical efficiency, have guided the development of the following recommendations.

Electric Storage Space Heating

The recommended strategy for electric storage space heating is the offering of load management contract rates. In those service areas where electric storage heating is cost-effective, the standard space heating rate is usually high enough ($\geq$ 3.0¢/kWh) to allow a rate discount adequate to give customers their required paybacks. If TES market penetration is expected to be high, the utility should consider installing ripple or other real-time control systems to maximize the load leveling benefits.

Storage Air Conditioning

Because the rate discount required to commercialize storage air conditioning is so large, utility ownership appears to be the only feasible strategy. Certainly in Service Area C, it would be difficult to devise any politically acceptable combination of monthly credits and energy-price discounts that would provide an adequate return on the customer's initial investment. In warmer climates, where energy use for air conditioning is much larger (for example, Service Area D), it may be possible to design and implement an acceptable load management contract rate.

Hot Water Heaters

Although storage water heaters with long storage times offer the greatest net savings (see Tables 5.1, 5.2, 5.3, and 5.4), they are not likely to be the easiest to commercialize. These systems require the customer to invest in a larger tank, whereas the systems with short discharge periods require only the the addition of a control device to the standard tank. A simple method to commercialize the smaller tanks is for the utility to offer the customer a credit (ranging from \$4.25 to \$9.50 per month for the utilities evaluated) for the right to interrupt service. For the larger tanks, the granting of a rate discount, usually of the order of 1¢/kWh, during the off-peak hours will provide an adequate payback on the customer's investment in the TES system.

5.4 R&D RECOMMENDATIONS

5.4.1 Overview

The outstanding study finding is that already-commercial and near-commercial customer TES systems are cost-effective in applications in U.S.

electric utility service areas. This finding has greatly influenced the R&D recommendations that follow. These recommendations are divided into two categories: R&D in support of near-term technology application and R&D to advance TES technology over the intermediate and long term.

5.4.2 *Near Term Applications*

All three types of storage systems examined in the first phase of the study are capable of near term application. Storage hot water heating and electric storage space heating equipment is available from domestic and foreign manufacturers. Storage air conditioning is at the prototype stage of development. Accordingly, the R&D recommendations in support of near-term applications are directed mainly toward removing near-term obstacles to application. The obstacles and ways to overcome them are as follows:

- *Lack of information on the part of utilities and utility regulators of the potential benefits of customer TES systems.* To overcome this problem, it is recommended that improved methods for assessing TES systems be developed and that these be made available to the electric utility industry. Using these techniques, utilities will also be able to assess the relative costs of such alternative customer systems as heat pumps, storage heat pumps, and storage resistance heating systems.

- *Lack of information concerning the performance characteristics of TES space heating and air conditioning systems.* To help overcome this problem, demonstration projects, sponsored jointly by the utility sector and ERDA, should be undertaken in different parts of the country. Data describing TES performance in providing building climate control and utility load control should be gathered, analyzed, and made available to the utility industry. Alternative control systems providing pre-set clock or real-time utility control over TES charging cycles should be evaluated. The conservation benefit commonly associated with the higher comfort level of the radiative heat component of electric storage heating should be measured and documented.

- *Absence of adequate vendor participation in the engineering and development of near-term storage air conditioner systems.* A number of development and demonstration projects involving air conditioner system manufacturers should be undertaken to promote development of and competition among different near-term system design concepts. Development and demonstration projects involving utility and manufacturer participation should be sponsored. In particular, manufacturers should undertake to develop and test air conditioners (heat pumps) that operate efficiently at lower (32°F) cold side temperatures and lower nighttime rejection temperatures.

- *Utility reluctance to undertake a TES commercialization program because of potentially complex legal, operational, and administrative problems.* Unfortunately, this situation is not readily amenable to outside solution. Therefore, technical assistance and planning support should be provided to those utilities indicating an interest in deploying TES systems. This could be especially helpful and effective with regard to smaller utilities, a number of which have demonstrated a strong interest in TES technology.

5.4.3 *Intermediate and Long Term Applications*

In a number of applications the operating temperature range available for the storage of sensible heat precludes the use of compact storage devices. Applications which could benefit from the development of suitable latent heat materials and storage devices include: cold side storage for air conditioning, hot and cold side storage for heat pumps, and hot side storage for solar absorption air conditioning. Given the large potential benefits, further R&D on phase change materials appears to be justified. However, it is also recommended that systems analyses be undertaken to better define phase change material application requirements and associated benefits.

Development of seasonal storage technologies could improve the overall economic efficiency of certain solar energy systems and those electric utility systems facing different winter and summer load growth. Solar storage ponds, underground aquifer, and seasonal ice storage are among alternative concepts worthy of study.

It is recommended that evaluation of the benefits of new storage technologies be initiated early in the research and development phases. The performance and cost of the new technologies should be measured against the performance and cost of commercially available systems. The three types of storage systems evaluated in this study should serve as reference technologies against which advanced diurnal storage concepts can be evaluated.

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APPENDICES

APPENDIX A

THERMAL ENERGY STORAGE COSTS FOR SPACE HEATING, AIR CONDITIONING, AND DOMESTIC HOT WATER SYSTEMS

This appendix presents an evaluation of the incremental capital investment costs to the consumer for TES in four geographical areas described in Chapter 4 and referred to as utility service areas A, B, C, and D. The analysis considers three forms of TES (domestic hot water, space heating and air conditioning) for three storage intervals (16, 8, and 4 hours). The incremental equipment and installation costs include both the TES and load management control systems. In all cases, incremental costs refer to TES systems installed during construction of a standard 1500 ft^2 single family house meeting minimum FHA standards.[1] This same standard house is used for all service areas.

SPACE HEATING

Space heating system requirements and costs were calculated for two winter peaking service areas (A and B) and one summer peaking area (C) having a household heating requirement similar to that of Utility B. The design-day parameters and conditions for the three areas are:

Utility Area	Design Temperature	Design (DD/DAY)	Consumption (kWh)	Capacity (kW)
A	-7	72	288	12.0
B	0	65	260	10.8
C	0	65	260	10.8

Because heating loads are not uniform over the diurnal cycle, the capacity figures have been modified for conventional systems and for storage systems having a short storage period (4 and 8 hours) to provide a reserve factor for peak load hours. Correction factors used were 1.2 for conventional, 1.10 for 4-hour storage, and 1.05 for 8-hour storage systems. For central systems, capacity and consumption values were increased an additional 10% to account for duct losses.

Table A.1 gives the cost algorithms used for conventional and TES systems; both dispersed and central systems were considered. The storage equipment and installation cost data were obtained from vendors of Swiss and German storage systems and from utilities currently installing the systems.[2] The installation costs consist of a fixed "hookup" cost which covers the electrical wiring and connection of thermostatic controls plus a variable installation cost. This variable cost covers the installation of the ceramic bricks into the central or dispersed storage units and the carpentry associated with installing baseboard or central resistive units. The central systems also involve an additional \$200 installation cost and a \$200 equipment cost for duct work. The controls include \$70 for a ripple control device plus \$150 for storage relay controls to prevent too rapid switch-on of the heater elements. These are necessary because up to 25 kW of charging capacity may be required for a 16-hour storage system, and instantaneous switching of this amount of power could have detrimental effects upon the utility distribution system.

Table A.1. TES and Conventional Systems Costs

System	Equipment (\$/household)	Installation (\$/household)	Controls Cost[a] (\$/household)
Dispersed Space Htg.			
Baseboard	\$28/kW	\$220 + \$28/kW	---
Storage Heater	\$180/unit + \$23/kW + \$6/kWh	\$220 + \$6/kWh	\$220[b]
Central Space Htg.			
Electric Furnace	\$400 + \$10/kW[c]	\$400 + \$10/kW[d]	---
Storage Furnace	\$380 + \$23/kW + \$6/kWh[c]	\$420 + \$6/kWh[d]	\$220[b]
Central Air Cond.[e]			
Conventional	\$100 + \$105/kW	\$100 + \$105/kW	---
Storage Cooling	\$300 + \$105/kW + \$8/kWh	\$300 + \$105/kW + \$8/kWh	\$140[b]
Domestic Hot Water			
Conventional	\$2.10/gallon	\$1.05/gallon	---
Storage	\$2.10/gallon	\$1.05/gallon	\$105

[a]All control costs include \$70 for ripple control equipment.

[b]Includes cost of relays and other control components.

[c]Includes \$200 for ducts.

[d]Includes \$200 for duct installation.

[e]All kW and kWh in electrical (not thermal) units.

AIR CONDITIONING

Air conditioning requirements were calculated only for the two summer peaking utilities (C and D). The sizing criterion depends upon both the design-day dry-bulb temperature and wet-bulb temperature. The design heat load in Btu/hr is given by:[3]

$$13{,}000 + 450(T_{Dry} - 73.5) + 585(T_{Wet} - 63.7)$$

For a coefficient of performance (COP) of 2.2 for the air conditioner, the following design-day values for the conventional air conditioning system are obtained.

Service Area	Dry-Bulb Temp. (°F)	Wet-Bulb Temp. (°F)	Consumption (kWh)	Capacity (kW)	Cooling Hours
C	90	77	62.9	3.7	17
D	106	77	84.6	4.7	18

The required storage capacity (kWh) and power rating (kW) depend upon the design-day load profile. The peak summer day utility load profile and the corresponding weather neutral load profile, typically occurring in spring or fall, were used to estimate design-day consumption and power requirements.

Cost algorithms used for conventional and storage systems are given in Table A.1. The incremental cost of TES cooling can be determined in a manner similar to that used for TES heating by assuming new-construction central units that operate with the same duct system as central heating. The three basic added costs introduced by TES cooling are primarily the cool storage system and secondarily a larger condenser/compressor unit to handle loads as high as 11 kW and an increased use of power resulting from storage inefficiency.[4] The equipment costs of TES cooling storage include the evaporators, water pump, ice sensor, expansion valve, and the cost of a plastic-concrete storage container, representing a lower cost bound.[5] From information obtained from air conditioning firms and building contractors, it appears that air conditioning system installation charges approximate the cost of the equipment. Central system air conditioning costs include compressor, blower, and evaporator costs, but exclude the cost of duct work, which has been assigned to the central space heating system. Installation costs are again equal to equipment costs. Control costs include the cost of a ripple system only.

HOT WATER HEATERS

The average per capita daily hot water usage has been estimated in all four geographical areas as:

	Gallons/Day/Person		
Function	Min.	Max.	Average
Personal	10	23	16.5
Laundry	2	4.5	3.25
Dishes	1	2.5	1.75
TOTAL	13	30	21.5

For an average household of 3.1 persons, the average daily hot water load would then be 66.6 gallons. In a 16-hour storage interval it is assumed that the entire load will be consumed, and that the hot water heater must also provide storage margins for imperfect stratification and insulation losses. Reference 6 shows that the thermaline is about 1.25 ft thick for an inlet-outlet water temperature differential of 70°F. During a Northern winter, this differential will be approximately 100°F., so that a stratification level of 1.8 ft is assumed. Based on winter inlet temperatures, and a nominal tank height of 5 ft, the storage unit would be only 64% useful, resulting in a 104 gal capacity to meet an entire day's load.

In evaluating the baseline (zero storage) hot water systems for cost comparison with storage systems, it was determined that the 18 gal/hr recovery rate (100°F temperature rise) of 4.5 kW electric heaters was adequate to handle the estimated peak rate usage of 14.3 gal/hr for the 3.1 person family unit. The lower insulation heat losses of small heaters would then suggest the use of 30 gal water heaters for the baseline case. However, the small incremental capital cost of 52 gal heaters that can accommodate larger family units has clearly shown itself to be a desirable feature for the resale market. For this reason the 52 gal heater is assumed as the minimum storage size.

Since the cost of insulation is small compared to the tank cost, hot water storage systems are taken to be 95% efficient relative to conventional hot water tanks; this is probably a conservative estimate.

The sizing of storage tanks is quite difficult to estimate due to the uncertain relationship between peak demand and average demand. Based on the experience of Detroit Edison and Buckeye Power, a standard size hot water tank has sufficient storage to satisfy a 4-hour storage demand. Thus, the only added cost is the ripple control unit. For 8 hours of storage, an 82 gal tank is deemed sufficient. This allows for 50% of a maximum day's consumption and 75% of an average day's consumption to be supplied during the 8-hour discharge period. For 16 hours a 120 gal tank is used. This allows for 80% of the maximum day's consumption and 110% of the average day's consumption to be supplied by the storage tank during the 16-hour discharge period.

Table A.1 shows the cost algorithms used for the domestic hot water tanks. The costs exhibit no economies of scale due to increased insulation costs associated with the larger tanks. Installation costs are based on 50% of equipment costs. Control costs consist solely of the ripple control device.

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3. This equation is based on a linear regression of sizing requirements presented in *Evaluation of the Air-to-Air Heat Pump for Residential Space Conditioning*, prepared for FEA by Gordian Associates, Inc., Contract FEA-CO-04-501771-00, April 23, 1976.

4. The net energy efficiency is 95% of the efficiency of the conventional system. This value was obtained from Robert Krubsack, Application Research Engineering, Wisconsin Electric Power Company, Milwaukee, Wisconsin, and represents actual field experience obtained from operating a proto-type ice-making storage unit. The net losses result from three

competing effects: (1) energy required for running the water pump and cold losses from the storage tank, (2) increased compressor demands due to lowered evaporator temperatures, and (3) reduced compressor demands due to cooler in-take temperature during nighttime operation.

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APPENDIX B

MARGINAL UTILITY SAVINGS AND TES COSTS

Marginal utility savings and TES costs were calculated for each of the four utility service areas. This appendix presents in graphical form the dependence of the marginal savings and costs on level of market penetration. The definition of the marginal concepts and their relation to total and average savings and costs are given in Fig. 3.1 of the text.

The service areas and TES technologies for which results are presented are as follows:

Service Area	TES System
A	Space heating Hot water heaters
B	Space heating Hot water heaters
C	Space heating Air conditioning
D	Air conditioning Hot water heaters

The shapes of the marginal benefit curves, as a function of the number of TES installations, reflect several competing effects. First, there are the large capital savings resulting from reduced generating and transmission capacity requirements. These benefits are eventually limited by scheduled-maintenance outage constraints and, in some cases, by the development of a secondary peak outside the TES discharge period. Second, there are distribution system cost savings which at first are large but which then decline as coincident TES loads add to secondary distribution system costs. The complicated structure of the marginal benefit curves for Service Area B is a result of all of these competing effects.

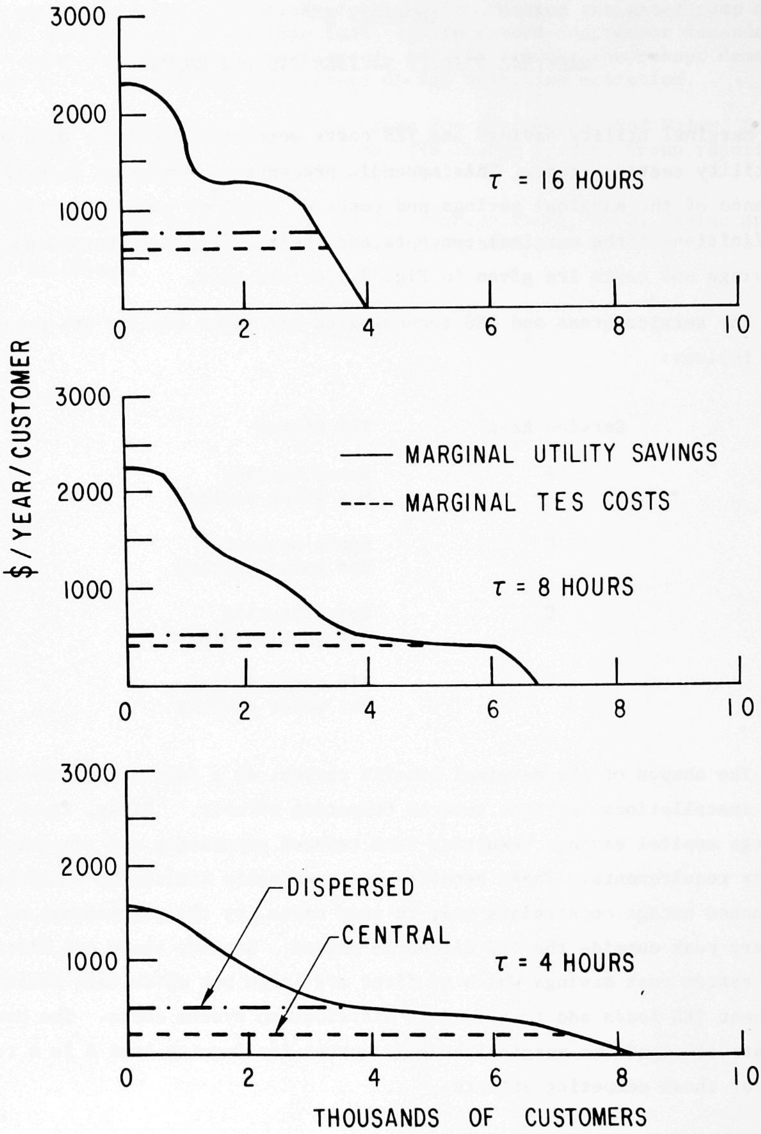

Fig. B.1. Storage Space Heating in Service Area A. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

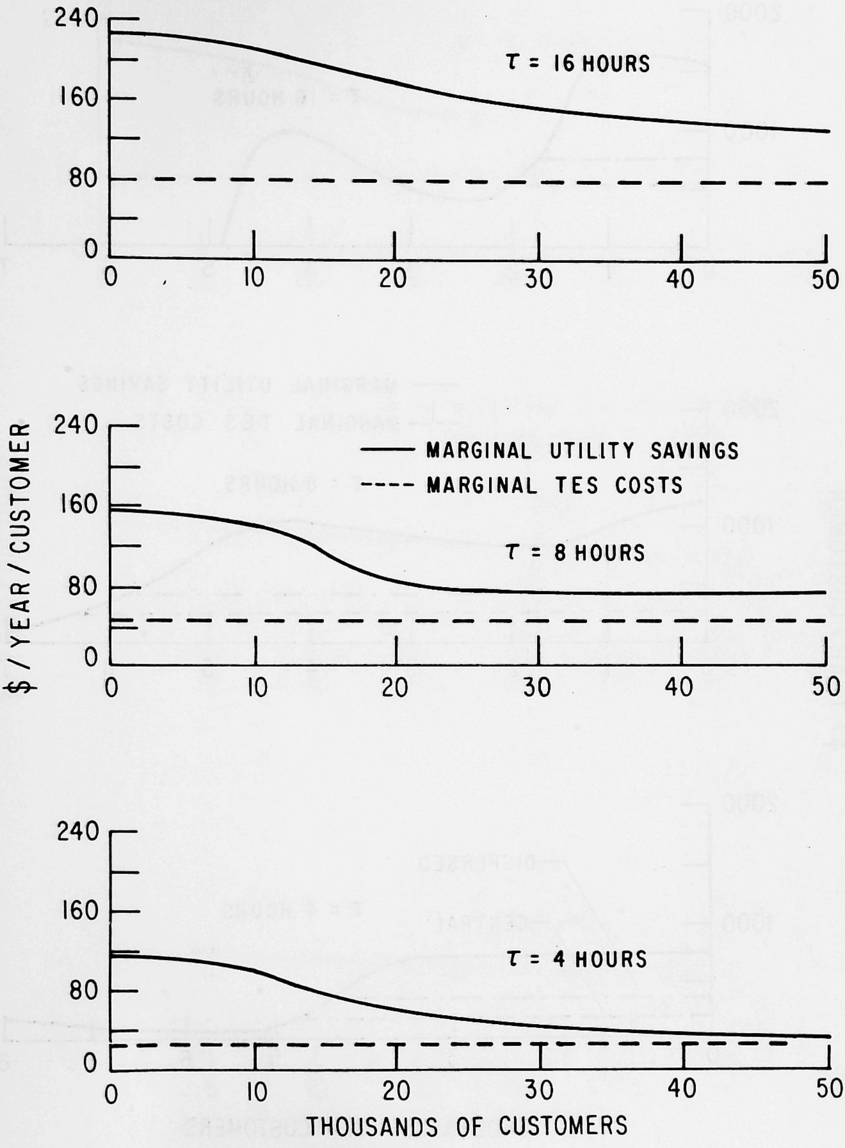

Fig. B.2. Storage Hot Water Heaters in Service Area A. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

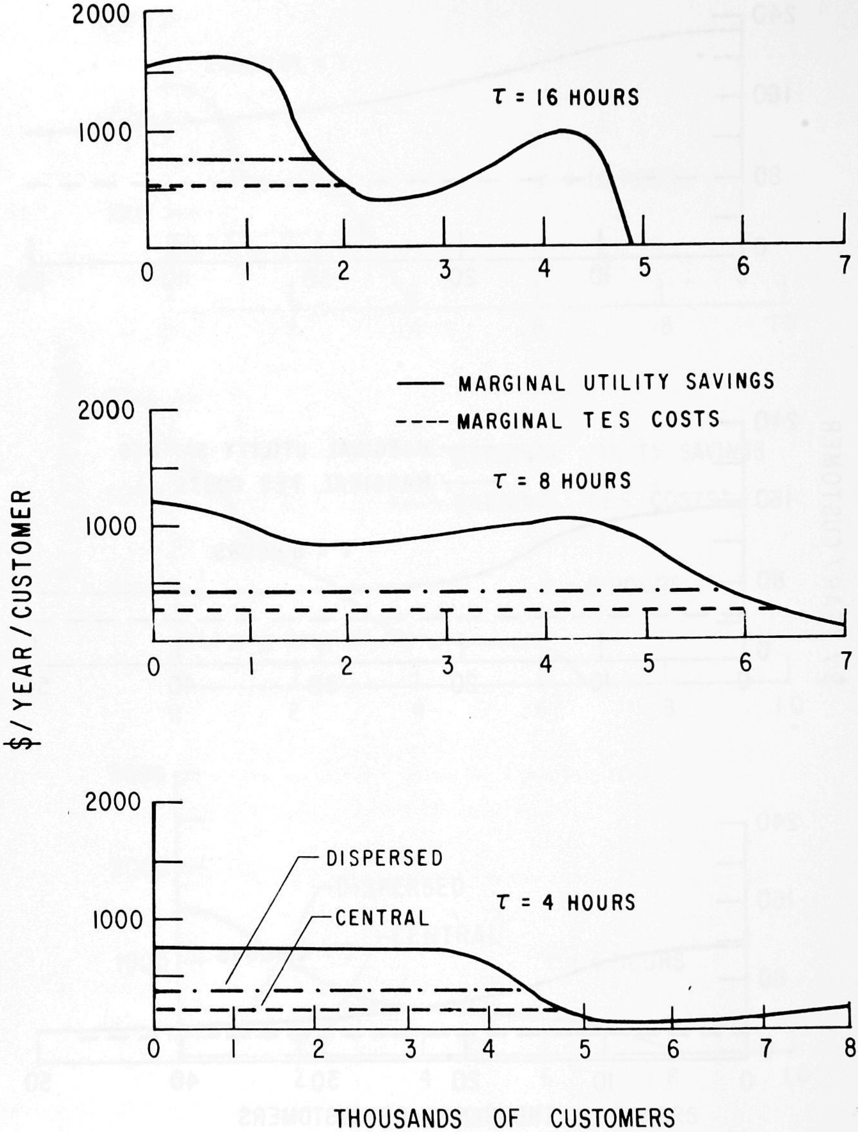

Fig. B.3. Storage Space Heating in Service Area B. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

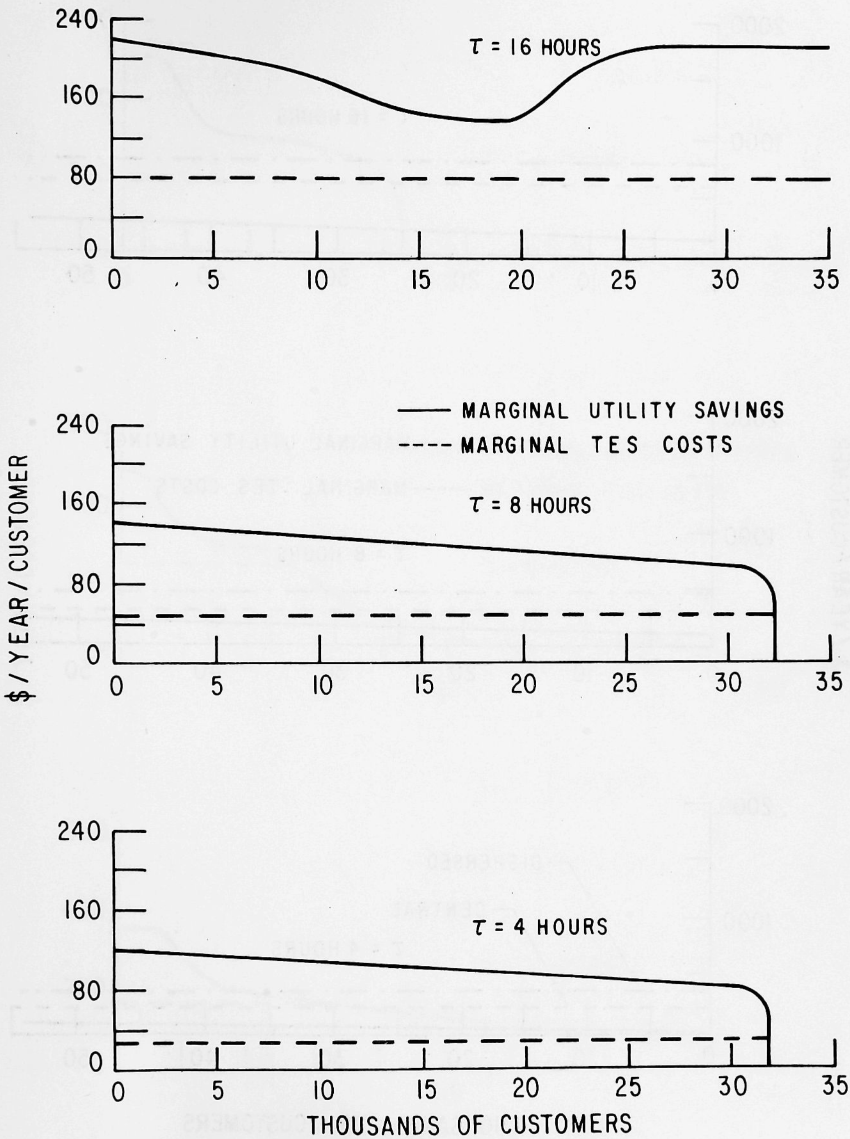

Fig. B.4. Storage Hot Water Heaters in Service Area B. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

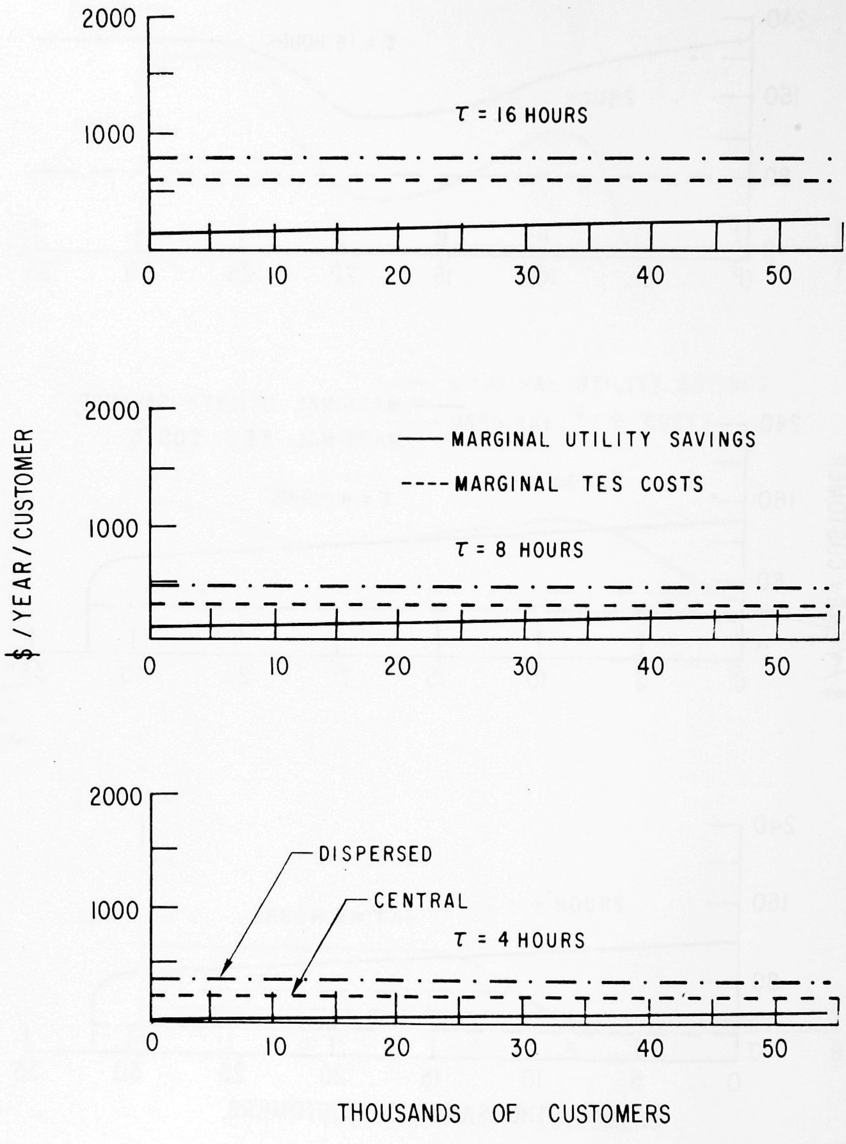

Fig. B.5. Storage Space Heating in Service Area C. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

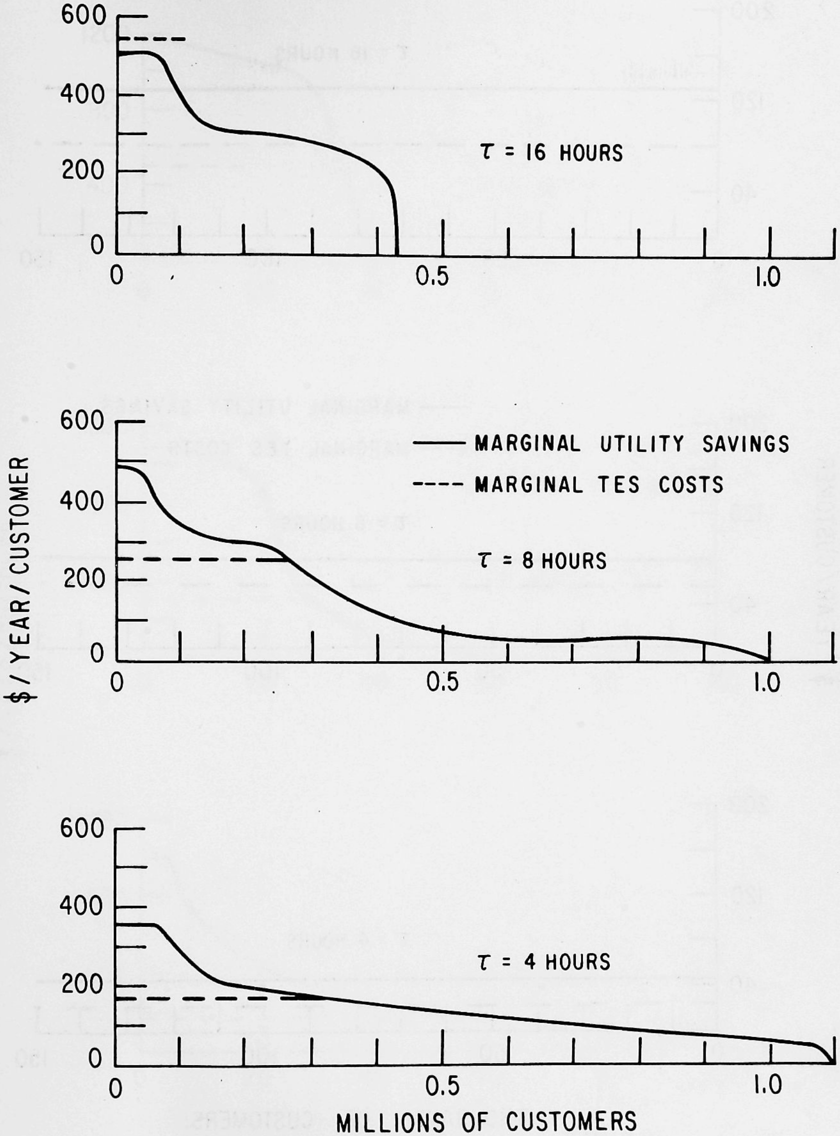

Fig. B.6. Storage Air Conditioning in Service Area C. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

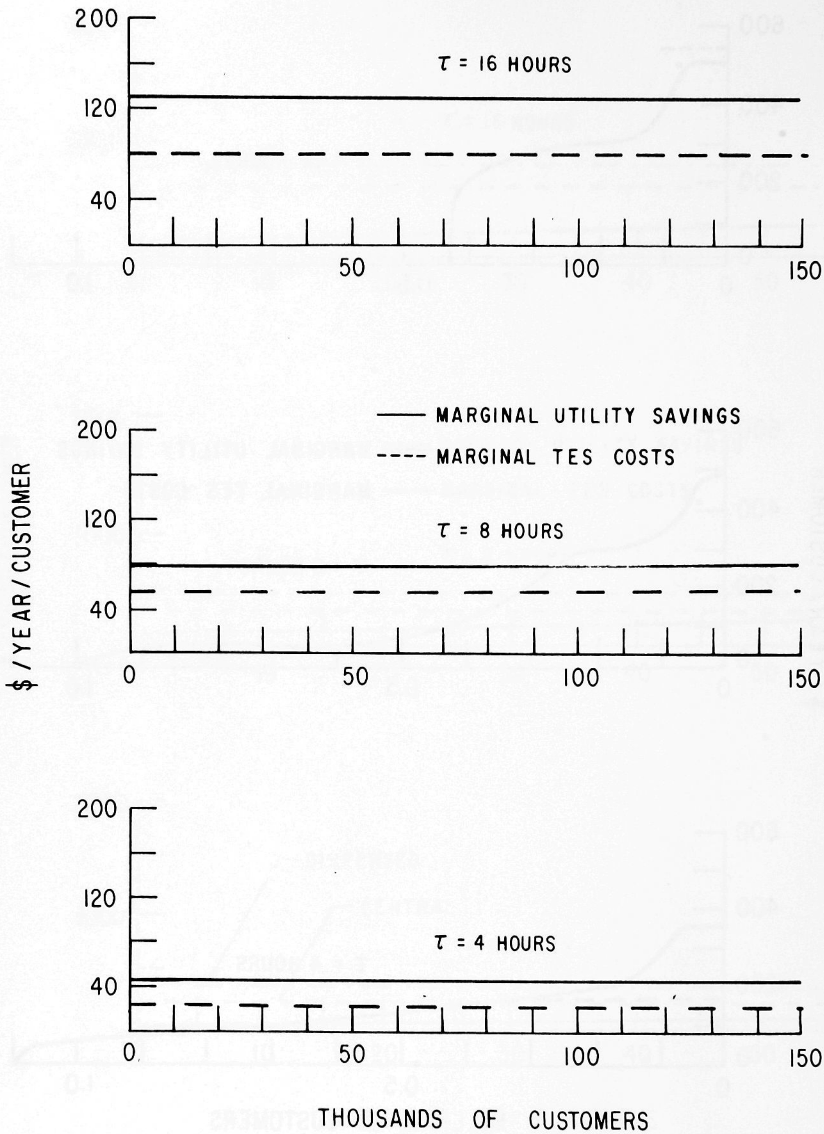

Fig. B.7. Storage Hot Water Heaters in Service Area C. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

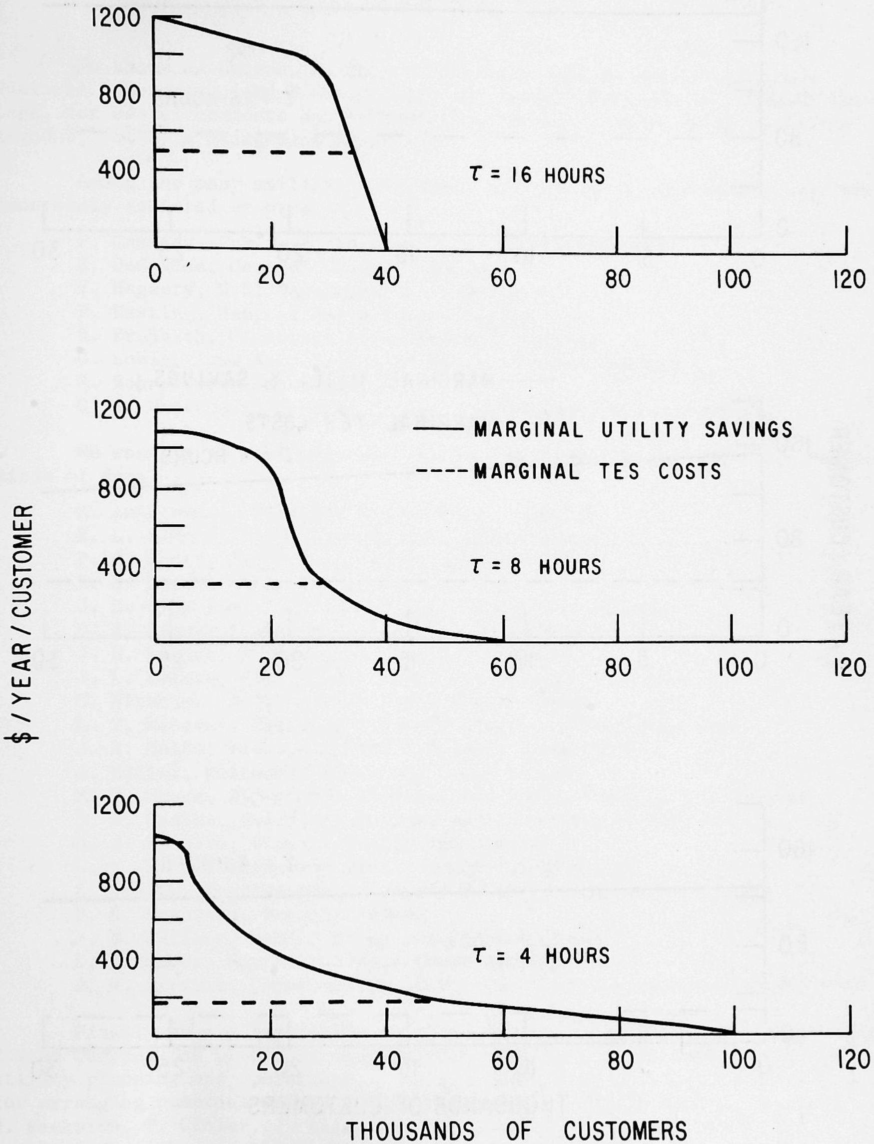

Fig. B.8. Storage Air Conditioning in Service Area D. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

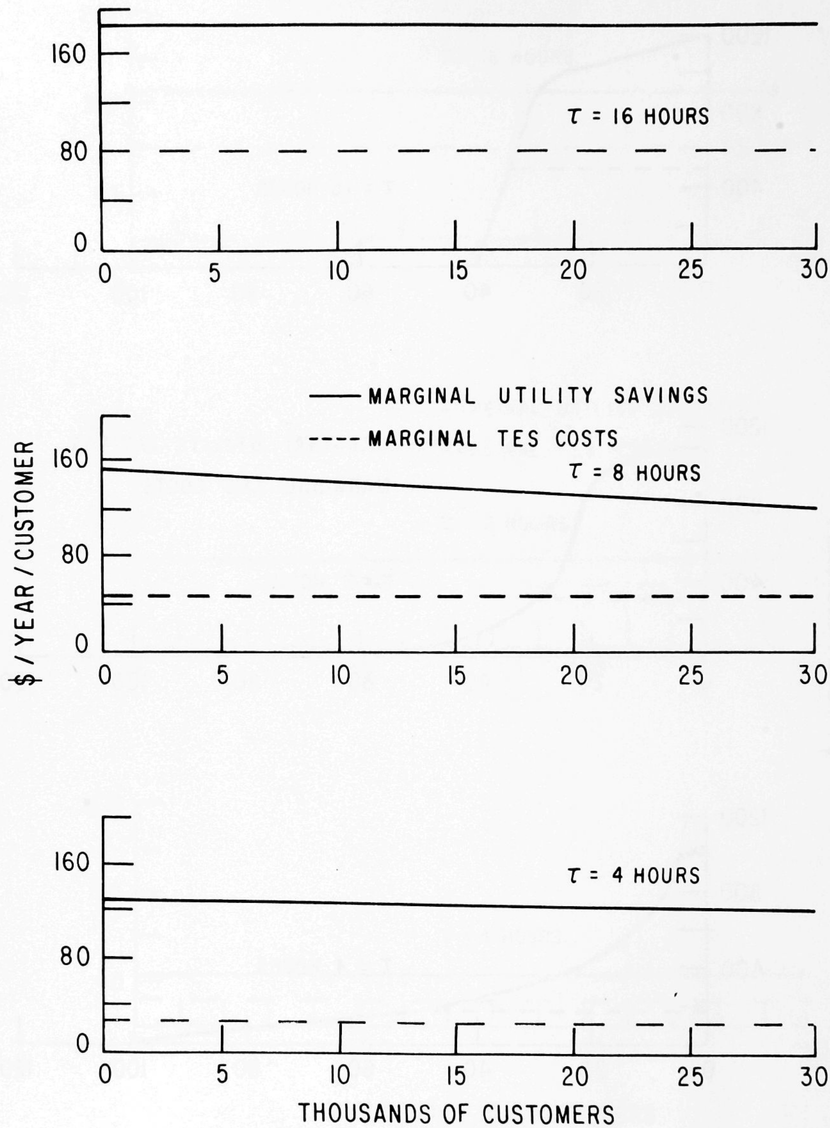

Fig. B.9. Storage Hot Water Heaters in Service Area D. Marginal Utility Savings and TES Costs for Different Discharge Periods, τ.

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